International Energy Agency

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ENERGY SUPPLY SECURITY 2014

Emergency Response of IEA Countries

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INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 29 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

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Foreword

The year 2014 is a special one for the International Energy Agency as we celebrate our 40th anniversary. In 1974, the IEA was founded with the primary mission of ensuring and improving global energy security. Today, energy security still remains at the centre of the IEA mandate. This publication returns to that core responsibility, providing an overview of the most recent five-year review cycle of our member countries' energy security and preparedness.

The world has changed dramatically since the founding of the IEA, driving the Agency to evolve and develop its capabilities accordingly. Oil demand patterns have shifted, and, where IEA members once accounted for around three-quarters of global demand, they now account for less than half. This is a challenge but also an opportunity. The IEA works to strengthen and deepen relationships with key partners, pursuing dialogue and information sharing – including in the area of emergency response. Accordingly, this publication contains overviews of emergency policies in Chile, China, India, and in the countries of the Association of Southeast Asian Nations (ASEAN).

While the IEA continues to evolve in response to changing energy security priorities, one thing remains constant, and that is the need to be prepared. The Emergency Response Review cycle provides regular peer assessments of emergency response mechanisms in each IEA member country. These reviews are not only a powerful tool for maintaining emergency preparedness among IEA members, but they also serve as a means to identify and share best practices among and beyond IEA members, thus helping to enhance an effective response to oil supply disruptions and strengthen energy security worldwide. The global nature of energy markets, and the oil market in particular, demands such breadth.

Still, energy security is no longer just about oil. Secure supplies of natural gas and electricity are also of growing importance for keeping our economies and societies functioning. The Emergency Response Review cycle described in this publication has been the first to start incorporating these expanded priorities. Natural gas security has become an integral part of our review process throughout this past cycle, while the current review cycle, already underway at the time of publication, also incorporates assessments of the electricity security of member countries. The more recent work on electricity is reflected and discussed in an annex to this publication.

Emergency oil stocks are a very powerful policy tool for mitigating short-term physical supply disruptions and for providing liquidity to allow market recovery. The stockholding system has undeniably worked well in the past. A recent IEA study, discussed in this publication, shows that not only has the system provided clear benefits, but it has done so at relatively low cost.

As this publication also demonstrates, emergency stocks are not alone in the IEA toolbox. Demand restraint measures, fuel switching capacity and other measures all contribute to a range of emergency response capabilities available to member countries.

As a result, the IEA stands ready to face future energy security challenges with confidence.

This publication is produced under my authority as Executive Director of the IEA.

Maria van der Hoeven
Executive Director
International Energy Agency

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Acknowledgements

Much of the information presented in this publication is drawn from the emergency response reviews (ERR) carried out in the cycle of 2008 – 2012. For that reason the IEA would like to acknowledge the assistance of all colleagues who helped us in preparing and conducting the reviews. We would also like to thank the Standing Group on Emergency Questions for their critical advice and comments.

This report reflects the work of the Emergency Policy Division of the IEA. Under the guidance of the Director of Energy Markets and Security Keisuke Sadamori and the leadership of Martin Young, Head of the Emergency Policy Division, the work was carried out by the following team:

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All errors and omissions are solely the responsibility of the IEA.

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Executive summary

The International Energy Agency (IEA) was created in 1974 with a membership of 16 OECD member countries. Its primary mandate was to implement the International Energy Program (I.E.P.), a joint strategy to address oil security issues on an international scale. The programme was a response to the international oil disruption of 1973 and to the wide-ranging macroeconomic problems it generated. Considerable changes have taken place in the energy world in the four decades since the founding of the IEA that have had an impact on both the nature and the scope of energy security.

In mid-2013, emerging market and developing economies overtook the OECD countries in oil consumption for the first time. Techniques such as horizontal drilling and hydraulic fracturing have opened access to oil and gas reserves that were previously considered too challenging or uneconomical to develop. North America is expected to become a net exporter of oil before 2030, while most other major oil-consuming regions and countries will rely on imports to a greater extent. Oil use is also increasingly moving towards Asia-Pacific markets and away from the Atlantic basin.

Natural gas has played an ever greater role in the world's energy mix, growing from 16% to over 21% of total primary energy supply (TPES) in the period since 1974. Natural gas demand in OECD non-member economies overtook that of the OECD countries in 2008. The natural gas market is becoming more global, thanks to the development of longer pipelines and inter-regional trade of liquefied natural gas.

Electricity security has become a growing concern in many emerging markets as well as in OECD member countries in recent years. Demand for electricity is set to rise faster than any other final form of energy, expanding by more than two-thirds over the period from 2011 to 2035. The steady increase in gas-fired electricity generation in OECD countries has strengthened linkages between the power and the gas sectors, increasing supply risks for both.

The role of the IEA in energy security

Emergency response is still one of the main pillars of the IEA. Membership requires countries to meet two key obligations: to hold oil stocks equivalent to at least 90 days of net oil imports; and to maintain emergency response measures that can contribute to an IEA collective action in the event of a severe oil supply disruption. Response measures include stockdraw, demand restraint, fuel switching and surge oil production.

The IEA Governing Board, a body comprising individuals at ministerial or senior official level, defines and determines the implementation of IEA policies. Under the Governing Board, the Standing Group on Emergency Questions (SEQ) is responsible for all aspects of the emergency response. The SEQ takes advice from the Industry Advisory Board (IAB) which is composed of experts from oil companies operating worldwide.

As part of its mandate, the SEQ conducts regular reviews (on a five-year cycle) of the emergency response mechanisms of member countries, ensuring the overall preparedness of the IEA for a rapid response to energy supply emergencies. These reviews help verify that emergency response capabilities have adapted adequately to changes in energy market conditions. The Agency expanded these reviews to cover

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natural gas security in addition to oil for the 2008 – 2012 review cycle, and recently also incorporated electricity security as part of its assessments for the latest review cycle which began in October 2013.

Recognising that oil consumption and net imports in some non-IEA countries are increasing rapidly, the IEA promotes dialogue and information sharing on oil security policies and shares information and experience about creating national strategic oil stocks with key transition and emerging economies, such as China, India and countries of the Association of Southeast Asian Nations (ASEAN). Expanding international co-operation with all players in the global energy markets to improve market transparency through the collection of more accurate and timely data is also a critical component of IEA work towards greater energy security.

Energy Supply Security: Emergency Response of IEA Countries 2014 reflects the results of the latest emergency response review cycle. It also draws attention to significant changes arising since the previous cycle of reviews and the last edition (IEA, 2007) of this publication. The findings contained in the following pages clearly illustrate the robustness of IEA emergency response systems. They also demonstrate the value of the periodic reviews as a means of fine-tuning specific response mechanisms in order to mitigate the effects of a shortfall in oil or natural gas supply. Most importantly, they highlight the reasons why being prepared is so important for the future.

Key findings

Over time, stockdraw has proven to be the most powerful mechanism available to IEA member countries during an oil supply disruption, but this publication also highlights progress in other areas. Demand restraint is another key measure that can help free up barrels by encouraging oil consumers to reduce their use of oil. This publication places particular emphasis on demand restraint within the transport sector, which currently accounts for more than half of all oil consumption in IEA member countries.

In the electricity market, oil and oil products have already been largely replaced by natural gas for electricity production. This means that the traditional backup fuel (natural gas) is already in high demand and not readily available. This integration suggests supply disruptions of other fuels, such as natural gas, could spill over into the oil market and cause increases in oil demand. Half of the member countries of the IEA have developed specific stockholding measures related to gas that would provide some resilience in the event of a disruption. Ministers from IEA member countries have tasked the IEA to monitor progress in gas markets and in the development of the gas security policies of its member countries.

Equally as important as having emergency response mechanisms in place is the ability to use them at short notice. The IEA has the ability to respond rapidly to an oil supply disruption through real-time communication with member countries and major players outside the IEA. The IEA also has a framework for decision making which is tested and updated through regular simulation exercises.

References

International Energy Agency (IEA) (2007), Oil Supply Security: Emergency Response of IEA Countries, OECD/IEA, Paris.

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Overview

Introduction

Against the backdrop of the oil crisis of 1973-74, the need to increase energy security was the main objective for the establishment of the International Energy Agency (IEA). Placing a particular emphasis on oil security, the Agency's founders – a collective of major energy-consuming countries – sought to create effective mechanisms for implementing policies on a broad spectrum of energy issues: mechanisms that were workable, reliable and could be implemented on a co-operative basis.

Forty years on, ensuring energy security is as urgent as ever. Whilst oil security remains a cornerstone of the IEA, the Agency is progressively taking a more comprehensive approach to emergency preparedness. Through periodic reviews, the Agency has strengthened and sharpened the emergency response mechanisms created to counteract short-term oil supply disruptions (see Chapter 2). The Agency has recently expanded these reviews to cover natural gas security as well (Chapter 3). This work continues to evolve, and the Agency has begun work to incorporate electricity security as part of its assessments of energy security and emergency response capabilities (see Annex A).

Defining energy security

The IEA defines energy security as "the uninterrupted availability of energy sources at an affordable price". Energy security has many dimensions: long-term energy security mainly deals with timely investments to supply energy in line with economic developments and sustainable environmental needs. Short-term energy security focuses on the ability of the energy system to react promptly to sudden changes within the supply-demand balance.

Lack of energy security is thus linked to the negative economic and social impacts of either physical unavailability of energy, or prices that are not competitive or are overly volatile. In cases such as the international oil market, where prices are allowed to adjust in response to changes in supply and demand, the risk of physical unavailability is limited to extreme events. Supply security concerns are primarily related to the economic damage caused by extreme price spikes. The concern for physical unavailability of supply is more prevalent in energy markets where transmission systems must be kept in constant balance, such as electricity and, to some extent, natural gas. This is particularly the case in instances where there are capacity constraints or where prices are not able to work as an adjustment mechanism to balance supply and demand in the short term.

Ensuring energy security has been at the centre of the mission of the IEA since its inception. The ability to respond collectively in the case of a serious oil supply disruption with short-term emergency response measures remains one of the core activities of the IEA. The long-term aspect of energy security was also included in the Agency's founding objectives, which called for promoting alternative energy sources in order to reduce oil import dependency. The IEA continues to work to improve energy security over the longer term by promoting energy policies that encourage diversification, both of energy types and supply sources, and that facilitate better functioning and more integrated energy markets.

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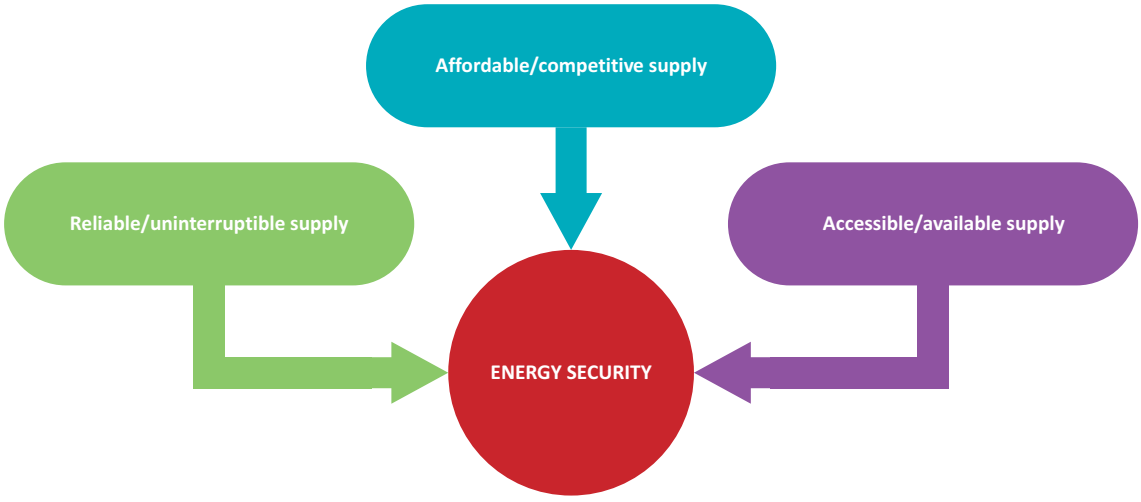
Figure 1.1 Defining energy security



Note: unless otherwise indicated, all tables, figures and boxes in this chapter derive from IEA data and analysis.

Establishment of the IEA

The impetus for the Agency grew out of fundamental changes in economics and politics associated with the international oil market leading up to the Middle East War of 1973-74. Oil demand had grown rapidly in countries belonging to the Organisation for Economic Co-operation and Development (OECD). A few decades earlier, oil had begun to erode the dominance of coal as a power source; by mid-century (1950s), it had taken over as the preferred fuel.

To a large degree, oil fuelled the rapid post-war economic growth achieved in OECD member countries. By the 1970s, petroleum was powering transportation, supplying one-third of industrial sector power and roughly one-quarter of electricity generation. This increase in demand for oil, coupled with a decline in oil self-sufficiency in the United States, created a situation in which OECD dependence on oil imports rose steeply in the years leading up to the crisis. Moreover, the Organization of the Petroleum Exporting Countries (OPEC) commanded a very large spare capacity of oil production, which added downward pressure on oil prices. The low prices and apparent abundance of oil encouraged its growing use.

The most vivid political impact of changing market conditions was the decision by Arab producers to use oil as an economic weapon. In October 1973, several countries belonging to the Organization of Arab Petroleum Exporting Countries (OAPEC, consisting of the Arab members of OPEC plus Egypt and Syria) took concerted action to reduce oil production from about 20.8 million barrels per day (mb/d) to about 15.8 mb/d (global oil demand in 1973 was 57.1 mb/d). Around the same time, OPEC opted to fix prices 400% above previous levels. In a relatively short time, the world's dominant energy source became scarce and expensive.

Overall, the embargo caused a shortfall in the international oil market that reached 4.3 mb/d. A significant reduction in spare capacity in non-OPEC countries further exacerbated the problem. OAPEC production cuts disrupted essential oil supplies to industrial countries, which could do little in the short run to reduce the price spike.

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These events alerted policy makers in the industrialised countries to the extent of their dependence on oil imports – and to the inherent vulnerability of this dependence. The 16 countries belonging to the OECD had very limited control over one of the commodities most vital to their economies, with no system in place to counter the potentially serious economic and political consequences of an oil supply disruption. These governments agreed to create the IEA and in November 1974 signed the Agreement on an International Energy Program (I.E.P. Agreement). This treaty laid the foundation for a multi-faceted system aimed at helping member countries cope with short-term oil supply disruptions in a co-ordinated and unified manner and build more resilient markets in the medium and longer term.

Box 1.1 Objectives of the International Energy Agency

The primary function of the IEA is to act as energy policy advisor for the governments of its 29 member countries, as well as the premier international energy forum to bring together both members and non-member partner countries and organisations – all with the aim of promoting reliable, affordable and clean energy for consumers. It was founded during the oil crisis of the early 1970's, with a mandate to coordinate measures in times of oil supply emergencies. This remains a core mission of the agency.

Governments of IEA member countries commit to undertaking joint measures to mitigate the impact of oil supply emergencies. In support of this commitment, they also agree to share energy information, co-ordinate energy policies and co-operate in the development of rational energy programmes. These provisions are embodied in the Agreement on an International Energy Program (I.E.P.), the treaty pursuant to which the Agency was established in 1974.

Since 1974, the IEA has kept pace with developments in the energy scene. Today the basic aims of the IEA are to:

- maintain and improve systems for coping with oil supply disruptions
- promote energy policies in a global context through co-operative relations with industry, non-member countries, and international organisations
- develop energy market analyses and forward-looking scenarios that can inform sound decisions making
- promote environmental sustainability and climate goals by encouraging the transition to a clean energy economy through technological exchange and sustainable policies.

Evolving oil market conditions

At the time of the creation of the IEA, oil demand in OECD countries represented nearly three-quarters of global oil demand. The oil crises of the 1970s triggered efforts to switch away from oil use towards other energy sources, such as the launch of large nuclear programmes in several countries. As a result, oil use in power generation dropped significantly. At the same time, a number of OECD countries developed domestic oil production. These factors significantly reduced OECD countries' dependence on imports; by the mid-1980s, dependence reached its lowest level since the 1960s, when the OECD first became a net oil importer.

Within ten years of having established the IEA, oil demand in OECD countries had fallen substantially and represented less than two-thirds of global oil use. However, by the second half of the 1980s growing demand for transportation fuels re-stimulated oil demand growth in OECD member countries, causing demand to outpace increases in domestic supply. As a result, OECD countries' dependence on imported oil steadily increased. Oil demand in developing countries, principally in Asia, also began to increase in the late 1980s, resulting in an ever-growing share of global oil demand outside of the OECD.

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Table 1.1 World oil supply and demand, 1985-2018 (million barrels per day)

	1985	1990	1995	2000	2005	2010	2012	2018*
OECD DEMAND								
Americas	19.1	20.7	21.8	24.3	25.9	24.1	23.6	23.3
Europe	12.8	13.8	14.8	15.3	15.7	14.7	13.7	12.9
Asia Oceania	5.7	7.4	8.9	8.9	8.9	8.2	8.6	8.2
Total OECD	37.5	41.9	45.4	48.6	50.5	47.0	46.0	44.4
NON-OECD DEMAND								
FSU	8.9	8.2	4.3	3.8	3.9	4.1	4.5	5.3
Europe	0.8	0.9	0.6	0.6	0.7	0.7	0.7	0.8
China	1.8	2.3	3.4	4.6	6.7	8.9	9.8	12.0
Other Asia	3.1	4.5	6.2	7.8	9.0	10.7	11.3	13.2
Latin America	3.1	3.5	4.1	4.7	5.0	6.1	6.4	7.4
Middle East	2.9	3.3	4.3	4.7	5.9	7.3	7.7	9.2
Africa	1.7	2.0	2.2	2.5	3.0	3.5	3.7	4.5
Total Non-OECD	22.3	24.6	25.1	28.6	34.1	41.4	44.0	52.3
Total demand**	59.9	66.5	70.5	77.2	84.7	88.4	90.0	96.7
SUPPLY								
Total OECD	20.3	19.0	21.0	21.9	20.2	18.9	19.9	23.7
Total Non-OECD (Non-OPEC)	20.3	22.7	20.5	22.6	27.2	29.9	29.5	30.9
Total Non-OPEC***	41.7	43.2	43.3	46.6	50.0	52.6	53.3	59.3
Total OPEC	17.6	23.9	27.4	30.8	34.8	34.7	37.6	
Total supply****	59.3	67.2	70.7	77.3	84.8	87.4	90.9	

Notes: Totals in table might not add up due to rounding.
* 2018 figures are forecasts.
** Measured as deliverables from refineries and primary stock, comprises inland deliveries, international marine bunkers, refinery fuel, crude for direct burning, oil from non-conventional sources and other sources of supply.
*** Non-OPEC supplies include crude oil, condensates, NGL and non-conventional sources of supply such as synthetic crude, ethanol and MTBE. This also includes "Processing gains" and "Other biofuels", which are not shown in either the Total OECD or Total non-OECD (Non-OPEC) lines.
**** Comprises crude oil, condensates, NGLs, oil from non-conventional sources and other sources of supply.
Source: IEA, 2013a.

In mid-2013, emerging markets and developing economies overtook the OECD countries in oil consumption for the first time. Non-OECD economies are expected to widen their lead in oil consumption, jumping from the 49% of global oil demand they accounted for in 2012 to more than 54% by 2018.

As with oil demand, there have also been significant shifts in sources of global oil supply since the time of the creation of the IEA. In 1974, over half of the world's oil was being supplied by OPEC countries. Sustained high oil prices triggered a substantial increase in non-OPEC supplies; production in the Soviet Union doubled between the early 1970s and the mid-1980s, and new frontier production was initiated in Alaska and the North Sea. These additional supplies, coupled with declining demand, resulted in a reduced share of a smaller market for OPEC producers. By the mid-1980s the share of global oil production coming from OPEC countries had declined to less than one-third. The producer group steadily regained market share after oil demand picked up from the low point it had reached in 1985. In 2012, some 41% of global supply came from OPEC countries.

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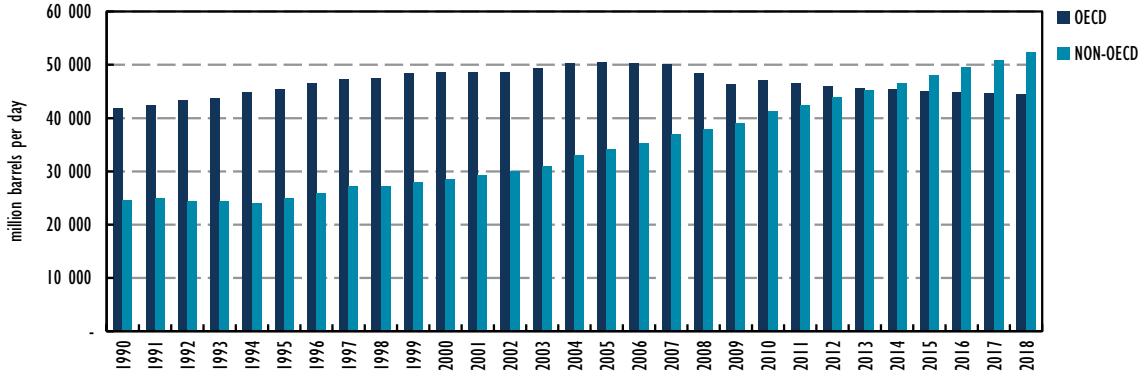
Figure 1.2 World oil demand, 1990-2018

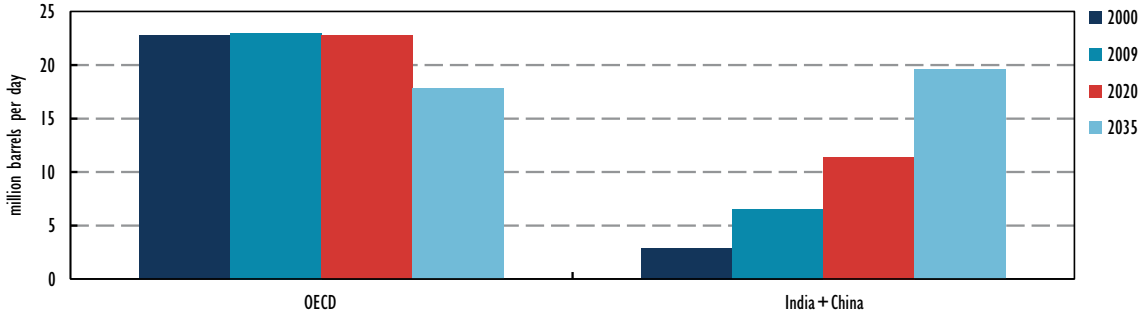


Note: 2014-18 data are forecasts.
Source: IEA, 2013a.

Oil production in the OECD as a whole peaked in 1997, and entered what was previously expected to be a path of long-term decline. However, a new trend has emerged recently because of the resurgence of oil and gas production in North America. Reserves which were previously considered too challenging or uneconomical to develop have become accessible through techniques such as horizontal drilling and hydraulic fracturing. The consequential increases in light tight oil (LTO) production in the United States, coupled with efficiency measures to curb oil consumption, will significantly reduce the country's oil import dependency. Canadian oil sands production is also expected to grow, amplifying the impact this will have on inter-regional global trade in crude oil. North America as a whole is on track to become a net exporter of oil before 2030 (*World Energy Outlook [WEO]*, 2013).

By reversing the trend towards greater dependency on imports, the United States stands out from most other major oil consuming regions and countries, which are expected to have a growing reliance on imports. Within the OECD regions, Japan and Korea remain almost entirely dependent on imports, whilst Europe is expected to steadily grow more import reliant. China and India will also grow more reliant on imports to meet future demand; the combined net oil imports of the two countries are expected to surpass those of the OECD by 2035 (*WEO*, 2013).

Figure 1.3 Total oil net imports, 2000-35



Source: IEA, 2013b.

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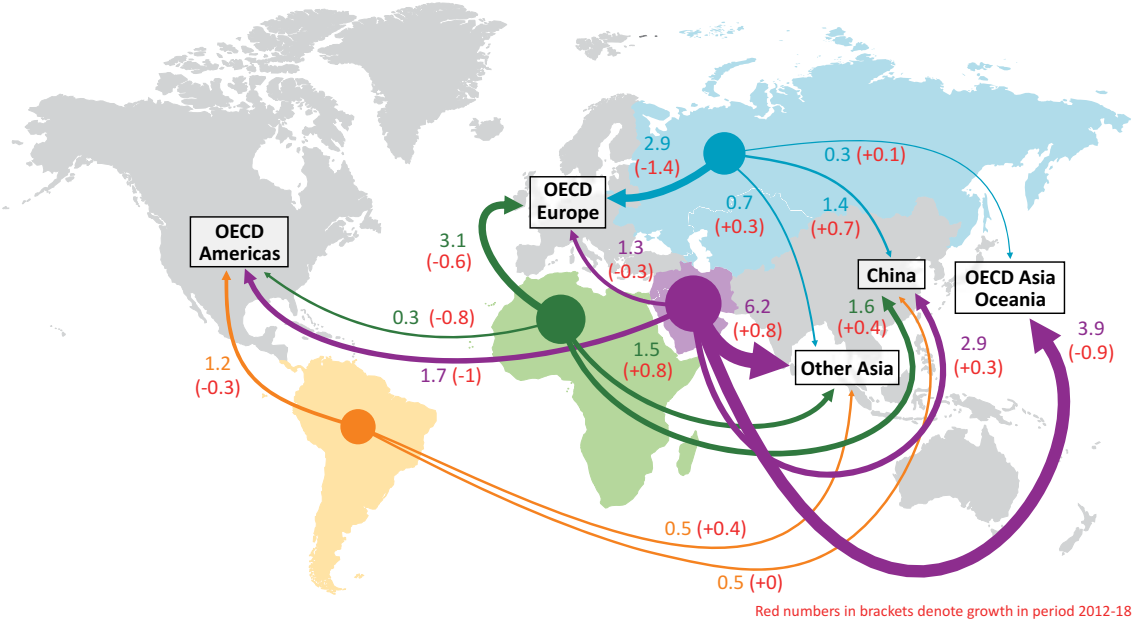
The changing oil map

The reduction in North American oil imports, in combination with rising oil consumption in emerging economies, is set to be a major driver for changing patterns of global oil trade. Increased domestic production in the United States has had the result of pushing out imports previously supplied to the country, primarily from the Middle East and West Africa. This is resulting in a visible eastward shift in global oil trade, as oil is being drawn increasingly towards Asia-Pacific markets and away from the Atlantic basin.

Figure 1.4 Crude exports in 2018 and growth over 2012-18 for key trade routes



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: IEA, 2013a.

Trends in global refining are also reshaping the map of world oil flows. An increasing amount of crude is being refined closer to production sources as well as the growing demand centres outside the OECD. As North American refining is increasingly supplied by regional production and more and more Middle Eastern crude is refined domestically, global trade in crude oil is expected to decline over the coming years. The bulk of this crude trade will be flowing to non-OECD countries, whose share of the global refining market is set to rise sharply and represent over half of all international crude imports by 2018. International trade in refined oil products is expected to increase as a consequence.

Continuing concentration of oil demand in transportation

The share of oil used for transportation has grown steadily since the 1980s. The transport sector accounts for well over half of global oil consumption today. This share is expected to rise further in the coming decades as oil demand for transport in emerging economies grows. In OECD countries, the transportation sector's share of oil consumption has grown from roughly 40% in the early 1980s to nearly 60% in 2011.

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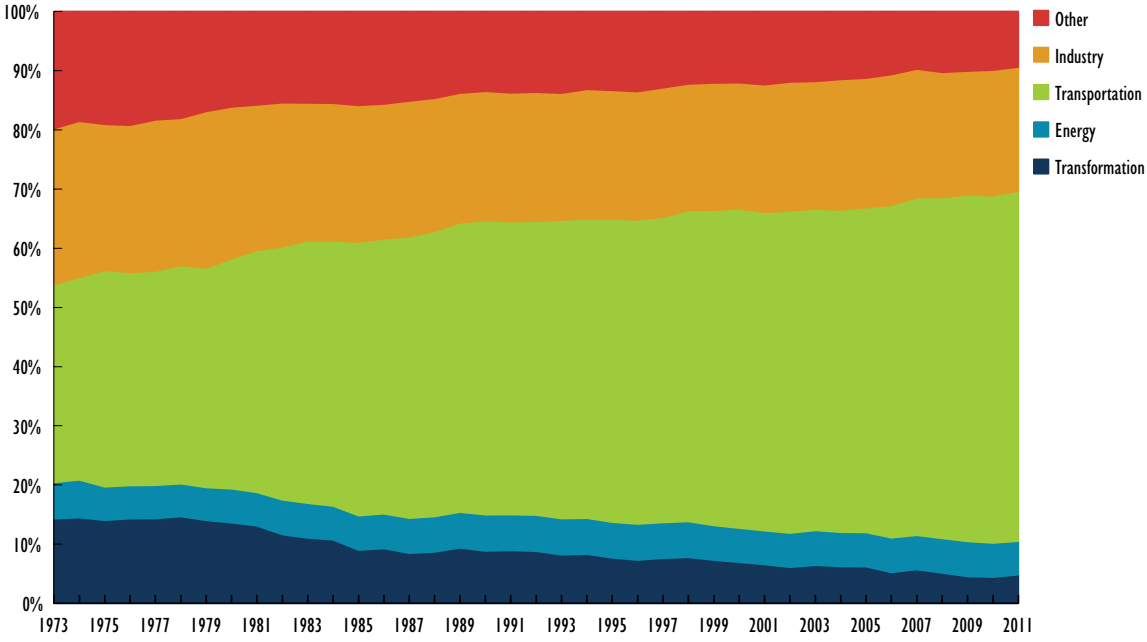
Figure 1.5 OECD oil consumption by sector, 1973-2011



Source: IEA, 2014b.

The increased concentration of oil usage in the transportation sector accentuates the potential economic impact of a supply disruption. Demand for transportation fuels is considered to have a relatively low "price elasticity", meaning that rises in fuel prices will typically result in relatively small and slow reductions in demand. This is due primarily to the lack of alternative options, particularly in the short-term, for consumers to switch away from oil-based transportation fuels.

Moreover, increased fuel costs pass rapidly through to other sectors of the economy; for example, rising transportation costs make delivery of foodstuffs and other products more expensive. In turn, retailers pass these rising costs on to consumers by raising the prices of goods. The longer oil prices remain at high levels, or the more they rise, the greater the threat to economic growth in importing countries. The burden is particularly heavy in developing countries in which food and energy already represent a high proportion of consumer spending.

Major oil supply disruptions and emergency response actions

There have been many supply interruptions since oil became a dominant energy source in the 1950s. The first significant disruption was the Suez Canal Crisis in 1956-57. This conflict limited oil traffic in the canal, effectively blocking the passage of approximately half of the canal's transit of oil. The estimated gross peak supply loss was around 2 mb/d. Since 1957, the oil market has experienced several significant disruptions, the largest being the Iranian revolution of 1978-79.

The severity of an oil supply disruption is not, however, only measured in the oil lost. It is also related to other factors, such as the level of commercial inventories, the likely duration of the disruption and available spare production capacity. More technical

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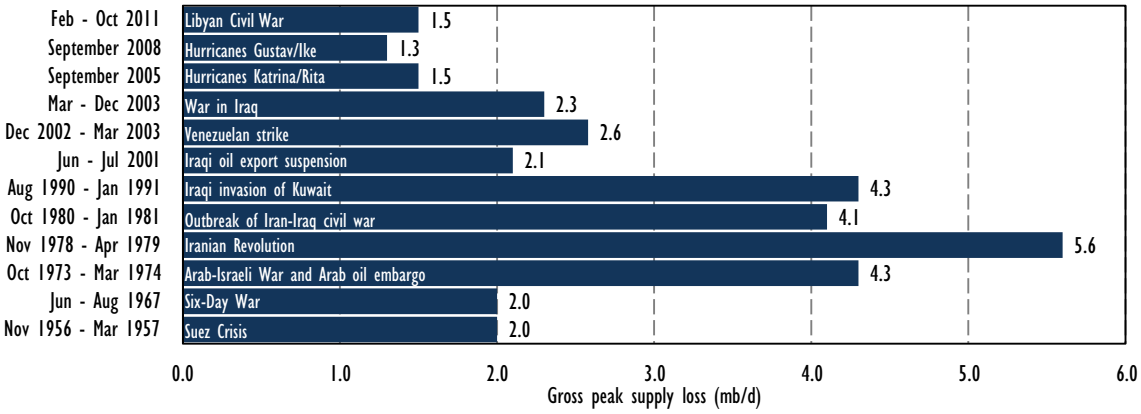
Figure 1.6 Major oil supply disruptions



factors play a role as well, such as the quality of the crude oil lost, seasonality trends and logistical issues. As such, all supply disruptions must be assessed individually.

The market context of an oil supply disruption determines when an emergency action is warranted. If the world market does not have sufficient excess capacity, a relatively small disruption can be quite severe. By contrast, a larger disruption in terms of gross peak

Box 1.2 The objective of an IEA collective action

The primary purpose of an IEA collective action is to mitigate the economic damage associated with a disruption of oil supply. By temporarily replacing disrupted supplies, the action is intended to help oil markets re-establish the supply/demand balance at a lower price level than would otherwise have been the case.

Managing oil prices is not the purpose of an IEA collective action, however, as high prices can have underlying causes which temporary emergency measures cannot address. Moreover, attempting to manage prices with emergency measures risks masking important market signals, such as the need to invest in supply infrastructure or more fuel efficient technologies, which are essential to assuring supply security in the future.

At the time the IEA was created, policy makers were primarily concerned with the physical unavailability of oil supplies and sought to define a threshold for activating an emergency response based on a specified volume of disrupted oil supply. Oil markets have changed enormously since the first oil shock of 1973-74. As a result of the liberalisation of the oil industry and the development of spot and futures markets, changes in supply and demand are quickly reflected in the international market prices of crude oil and refined products. Increases in spot prices quickly feed through into higher retail prices and the very notion of a "supply shortfall" is misplaced: a reduction of supply would cause prices to rise immediately whilst higher prices would lead to lower demand and bring the market back into balance. However, this rebalancing might require prices to increase substantially in response to a relatively small fall in supply, given the high concentration of oil use in the transportation sector where few short-term alternative options exist.

In the absence of price controls that might cause physical shortages, a sudden fall in global oil supply can cause economic damage through sudden price increases. The purpose of an IEA collective action is to limit the extent and impact of a sudden fall in global oil supply caused by a disruption. In such instances, IEA countries would want to replace lost supplies on a temporary basis in order to prevent economic damage, but they would still allow the market to set the price. Such a move is best described as an effort to stabilise the market rather than to manage prices.

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supply loss can be manageable in the short term if there is sufficient spare production capacity or commercial oil stocks to offset the oil supply loss.

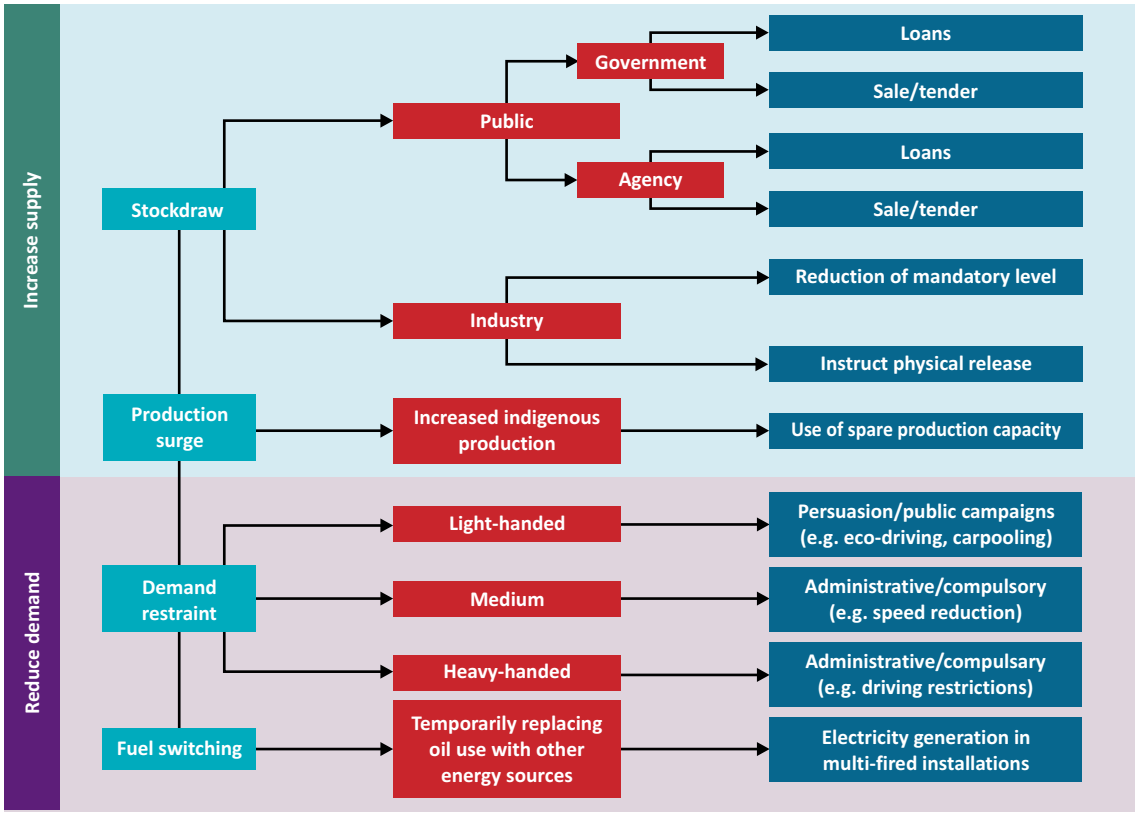
IEA emergency response mechanisms (described in further detail below) were established to create a concrete and co-operative action plan in the event of a major oil supply disruption. These measures were initially designed to take effect in the event of oil supply disruptions involving a loss of 7% or more of normal oil supply, either for the IEA as a whole or any individual member country. However, as oil markets have evolved, so have the tools of the IEA for responding to supply disruptions. In the event of a supply disruption, a detailed impact assessment is used to determine how and when to resort to emergency measures.

Since the creation of the IEA, member countries have taken collective action on three occasions: in the build-up to the Gulf War in 1991; after hurricanes Katrina and Rita damaged offshore oil rigs, pipelines and oil refineries in the Gulf of Mexico in 2005; and in response to the prolonged disruption of oil supplies from Libya in 2011 (for more information on these actions, see Annex F).

IEA emergency oil response measures

Forty years after the establishment of the IEA, emergency response to oil supply disruptions remains a core mission of the IEA. The Agency's collective response capabilities aim to mitigate the negative impacts of sudden oil supply shortages

Figure 1.7 IEA emergency response system



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by making additional oil available to the global market. This is achieved through a combination of emergency response measures designed to increase supply and reduce demand with stock release as the preferred option.

The IEA emergency policy focuses on alleviating short-term oil supply disruptions. It is not a tool for price intervention or long-term supply management, both of which are more effectively addressed through other policies that the IEA encourages, such as: oil import reduction, energy efficiency, energy diversification, or research, development and investment in alternative energy technologies.

Box 1.3 How does the IEA system work in practice?

In the event of an actual or potentially severe oil supply disruption, the IEA Secretariat first assesses its market impact and the need for an IEA co-ordinated response. The assessment includes an estimate of the market's net loss of oil, taking into account any spare production capacity that can be quickly brought on line following an exchange of information with producers, producing countries' governments and international organisations.

This assessment is the basis on which the IEA Executive Director then consults with and provides advice to the IEA Governing Board.[1] In the past, this consultation process to determine the need for IEA co-ordinated action and subsequent recommendation has been accomplished within 24 hours.

Once the need for co-ordinated action has been agreed, member countries participate according to national circumstances. Each member country's share of the total response is generally proportionate to its share of total IEA oil consumption.

Throughout the decision-making and implementation process, IEA stakeholders benefit from the input and advice of industry experts through the IEA Industry Advisory Board (IAB, established in 1975). In order to fulfil its role, the IAB participates regularly in IEA meetings on oil supply security. The IAB membership is drawn from the major oil companies with headquarters in IEA countries.

Measures to increase oil supply

Stockdraw

Among the emergency response measures at hand, stockdraw is the most commonly used: it is the most effective first line of defence for providing additional oil to an under-supplied market and can be complemented by other emergency measures during a co-ordinated action.

IEA countries are obliged to hold stock levels equivalent to at least 90 days of their net imports (see Chapter 2, Box 2.1). Stocks are generally held either by industry or a combination of industry and a public entity, i.e. by the government and/or agency established to fulfil this role. During an oil supply disruption, member countries can release stocks through various options. In countries where there is a substantial obligation on industry to hold stocks, the most common course of action is for the government to allow, temporarily, a decrease in industry's compulsory stockholding levels in line with the country's share of the total IEA response. For countries with publicly held stocks, stock release typically involves offering specified amounts from these public reserves for sale or lease. (Stockholding arrangements are described in detail in Chapter 2; for a country-by-country analysis, see Chapter 4.)

1. The IEA Governing Board is the IEA highest political decision-making body comprising ministers and/or their representatives.

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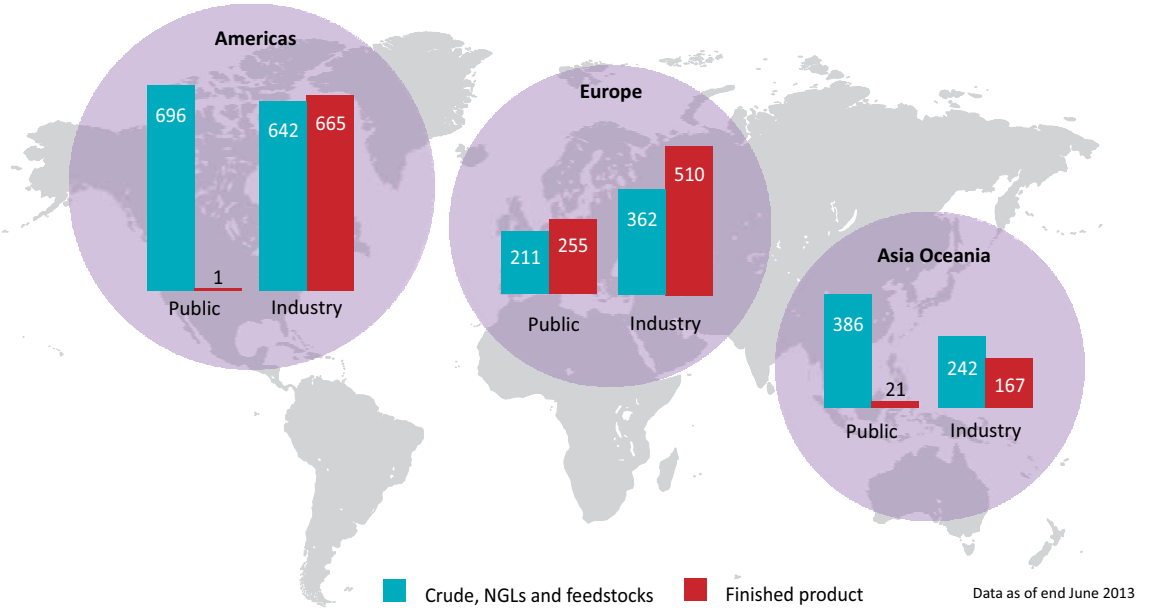
Figure 1.8 Total oil stocks in IEA regions

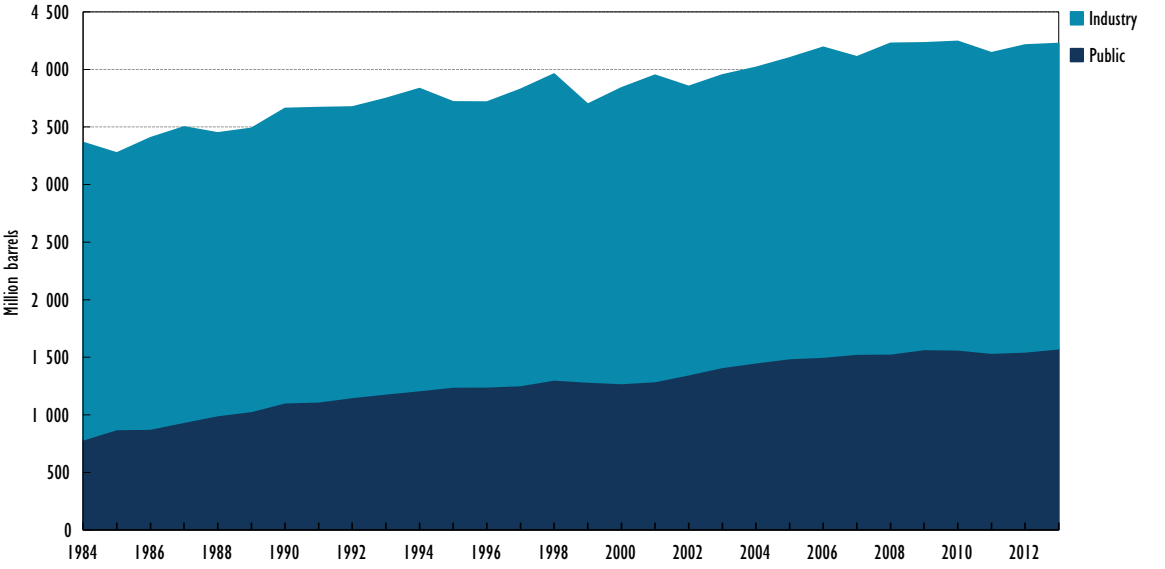


This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Note: oil stocks as of end-June 2013.
Source: IEA, 2014b.

Total oil stocks in IEA countries amounted to just under 4.2 billion barrels as of end-June 2013. More than 1.5 billion barrels of this amount was in the form of public stocks, held exclusively for emergency purposes. The 2.6 billion barrels of industry stocks include both stocks held to meet government imposed minimum stockholding obligations and stocks held for commercial purposes.

Figure 1.9 Total oil stocks at year end, 1984-2013*



*End-year oil stock levels; 2013 is level at end-June.
Source: IEA, 2014b.

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The IEA minimum stockholding requirement does not stipulate the type of oil held; it can be met with stocks of either crude or refined products. In this respect, there are important differences in the composition of stocks held publicly or by industry. At present, some 83% of publicly held stock is in the form of crude oil. By contrast, industry holds roughly 45% in crude oil and the majority in oil products.

Significant regional differences in stockholdings are also evident. In IEA North America, over 65% of all stocks and virtually all public stocks are in the form of crude oil. IEA Europe holds a greater share of oil products, reflecting EU regulations on stockholding (see Chapter 2 and Annex D). In IEA Pacific, three-quarters of all stocks are in the form of crude oil and in IEA North America the vast majority of publicly held stocks (95%) are also crude oil.

The aggregate stock level for IEA countries of 4.2 billion barrels is a significant increase from the mid-1980s, when these barely reached 3.0 billion barrels. The steady growth of aggregate stocks reflects the increase in oil demand and subsequent net imports resulting in larger stockholdings, political decisions by some member countries to increase their public stockholding, as well as increased IEA membership.

Production surge

Surge production is another emergency response measure designed to increase the availability of oil supply. More specifically, it is a short-term measure to increase indigenous oil production within a very short period of time. The measure is limited to member countries with significant levels of production, and the potential volume available in a crisis depends on the amount of spare or surge production capacity maintained in individual member countries.

In the current oil market climate, this option is much less viable: overall, IEA countries have little or no spare capacity. In addition, the need to maintain good oilfield practices limits the extent to which oil production can be increased on a short-term basis.

Measures to reduce oil use

Demand restraint

Short-term reductions in the use of oil are an important part of any response to a supply disruption; the most important means of achieving this is through demand restraint measures. One of the key goals of demand restraint measures is to free up oil in an under-supplied market. Such measures are not restricted to one particular sector of consumption. For instance, in the residential sector when oil is used for heating, oil consumption can be substantially reduced through publicity campaigns that encourage people to turn down the thermostat a few degrees during the winter. Where the industry sector uses oil for power, a possible limit on operating times may be effective for reducing consumption.

Because of the high – and increasing – proportion of oil used for transportation, most demand restraint policies focus on this sector. This sector is more multi-faceted and requires a range of measures. At one end of the spectrum, measures can be very light-handed such as encouraging people to drive less, to carpool or to drive more efficiently. At the other extreme, governments can impose very heavy-handed measures, such as rationing or allocation of oil. (See Chapter 2 for more details on demand restraint capabilities in IEA countries.)

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Fuel switching

Fuel switching is another measure that, similarly to demand restraint, seeks to reduce the use of oil during a supply disruption. It is a short-term measure that encourages the use of other energy sources as alternatives to oil. This includes, for example, using coal or natural gas rather than oil in electricity production.

The actual potential to use fuel switching in a crisis has declined significantly in member countries since the 1970s. In particular, the growth in natural gas and gas-only power stations leaves little scope for fuel switching in power generation. Oil-fired electricity generation in IEA countries has declined significantly since 1973, when oil accounted for close to 25% of electricity generation, compared to around 3% in 2012. An increasing share of oil is used in the transport sector. In 1973, this sector accounted for less than 35% of oil consumption; this percentage had increased to nearly 60% in 2011. In the short run, there is virtually no potential to switch to other fuel sources for transportation. (Chapter 2 has a more detailed analysis of fuel switching capabilities in IEA countries.)

Being prepared is key

The emergency measures available through the IEA would not be sufficient to effectively deal with a disruption in oil supply without continuous monitoring and communicating of regular updates on the global oil market, along with regular training and testing. The IEA pursues a range of preparatory activities, many of which require direct participation by member countries.

IEA analysts continuously monitor the market. The Agency collects comprehensive oil data from OECD member countries on a monthly basis. It also gathers data for non-OECD member countries on a periodic basis, according to availability. In the case of a crisis, the regular reporting of data is complemented by additional information gathered from various sources, including specific emergency questionnaires. IEA oil market analysts use these data for various purposes. Every month, the IEA publishes the *Oil Market Report*, which highlights results of its in-depth data collection and analysis of the oil market, focusing on current issues such as demand, supply, stocks, price and refining. In addition, the Agency produces internal daily and weekly reports as well as annual *Medium-Term Market Reports* to analyse market trends five years forward. Its strong analytical capabilities enable the IEA to assess supply disruptions quickly and to provide member countries with timely and appropriate information.

The IEA system's ability to communicate with its members on a real time basis across continents enables it to reach decisions within hours. It reinforces this ability by periodically conducting emergency response exercises (EREs), which are made up of a series of workshops and exercises to train and test policies, procedures and personnel. In addition to the participation of all member countries, the Agency invites candidate countries and major consuming non-member countries to participate. The objective is to ensure countries' readiness to act quickly and effectively by simulating the decision-making process.

In a five-year cycle, the IEA Secretariat and member country representatives conduct peer reviews of each IEA country's national emergency preparedness. These reviews assess procedures and institutional arrangements. Each member country then receives its report with recommendations; reports and recommendations are discussed by all member countries.

A critical component of the IEA crisis management strategy is robust dialogue with major oil producers and the OPEC Secretariat. IEA and OPEC have already co-operated

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on a number of occasions to mitigate the effects of an oil supply disruption as both organisations have a clear interest in the stability of the world oil market.

Recognising that oil consumption and net imports in some non-member countries are increasing rapidly, the IEA promotes dialogue and information sharing on oil security policies and shares information and experience on creating national emergency oil stocks with key transition and emerging economies, such as China, India and countries of the Association of Southeast Asian Nations (ASEAN). Expanding international co-operation with all players in the global energy markets to improve market transparency through the collection of more accurate and timely data is also a critical component of IEA work towards greater energy security.

Box 1.4 Quantifying energy security

Historically, energy security was primarily associated with oil supply. Whilst oil supply remains a key issue, the increasing complexity of energy systems requires systematic and rigorous understanding of a wider range of vulnerabilities. Disruptions can affect other fuel sources, infrastructure or end-use sectors. Thus, analysis of oil supply security alone is no longer sufficient for understanding a country's energy security situation as a whole.

One of the ways in which the IEA is responding to this challenge is by developing a comprehensive tool to measure energy security. The Model of Short-term Energy Security (MOSES) examines both risks and resilience factors associated with short-term physical disruptions of energy supply that can last for days or weeks. MOSES extends beyond oil to monitor and analyse several important energy sources, as well as the non-energy components (such as infrastructure) that comprise an energy system. Analysis of vulnerability for fossil fuel disruptions, for example, is based on risk factors such as net-import dependence and the political stability of suppliers. Resilience factors include the number of entry points for a country (e.g. ports and pipelines), the level of stocks and the diversity of suppliers. For more information on MOSES, see Annex B.

An evolving energy landscape

Since the founding of the IEA, considerable changes have taken place in the energy world that have impacted both the nature and scope of energy security. Whilst the share of oil in the world's energy supply mix has declined, it will remain the most important fuel in the world's primary energy supply for the foreseeable future. Oil will continue to play a vital role in the economic health of the global economy, particularly in the transportation sector where oil dependency has remained high and there are few viable alternatives. It remains as critical as ever to have effective and rapidly deployable emergency response measures. Yet fundamental changes, such as the growing share of global oil demand from countries outside the IEA and the shifting patterns in global oil market flows require continued vigilance that emergency response systems remain effective.

Natural gas has taken on an ever greater role in the world's energy mix, growing from 16% to over 21% of total primary energy supply in the period since the IEA was created. In IEA countries, natural gas accounted for over 25% of the total primary energy supply mix in 2012. Natural gas markets have become more integrated, and as most major consumer countries become more reliant on imports, a greater share of gas is supplied via longer pipelines and longer liquefied natural gas (LNG) routes. Given the rising importance of natural gas as an energy source and the increasing physical distances between production and consumption, there is a growing need to assess countries' vulnerabilities and response options for dealing with a severe disruption. For this reason, the IEA included natural gas in the most recently concluded round of emergency

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response reviews of member countries. The results of these reviews, covering oil and gas emergency response, are examined in more detail in the following chapters.

In recent years, electricity security has become a growing concern in many emerging markets as well as in OECD countries. Demand for electricity is set to rise faster than any other final form of energy, expanding by more than two-thirds over the period from 2011 to 2035 (*WEO*, 2013).There is a formidable need for global energy investment to meet growing demand from emerging countries and to replace ageing generation capacity in OECD countries. Another important challenge will be integrating an increasing share of variable renewable energy generation without jeopardising security of supply. Natural gas is gaining prominence as a primary fuel for power generation, providing flexibility to base load and critical peak power and setting the price of electricity. As such, gas and electricity markets are increasingly intertwined in security, cost and reliability. The IEA is undertaking work to expand its analysis to cover electricity security by including the topic in emergency response reviews. Based on these developments, future updates to this publication will include detailed analysis of electricity security in individual IEA countries.

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Emergency oil response systems in IEA countries

Introduction

The emergency response systems of International Energy Agency (IEA) member countries are mechanisms through which the Agency is able to co-ordinate actions to mitigate the effects of short-term oil supply disruptions. Part of the IEA mandate is to ensure that the measures remain effective as the oil market evolves. To this end, the IEA conducts country-by-country Emergency Response Reviews (ERRs) on a regular basis. While the scope of these reviews has been broadened beyond just oil, reviewing the ability of IEA countries to cope with short-term oil supply disruptions remains a primary focus. This chapter summarises the findings of the oil portion of the latest cycle of reviews, which was concluded in 2012.

Decision-making structure

In most IEA countries, the responsibility for oil security policy ultimately rests with one particular government minister. Security policy encompasses decisions regarding the release of emergency oil stocks or implementation of other emergency measures.

The minister typically delegates responsibility for the preparation and implementation of national emergency measures to the country's national emergency strategy organisation (NESO), along with the task of liaising with the IEA on matters of international co-ordination during an emergency. The structures of NESOs differ from country to country, reflecting a wide variety of oil supply and political structures.

NESOs also involve oil industry personnel to varying degrees. The permanent core of the NESO structure usually comprises oil market experts from within the government department concerned with energy matters. When activated during an emergency, the NESO structure expands to include a broader range of government offices and industry representatives. Most NESOs have a dual mission: in addition to holding governmental authority for national oil emergency management, they monitor domestic oil market activities.

Stockholding requirements

In accordance with the International Energy Program (I.E.P.) Agreement, each IEA country has an obligation to hold oil stocks that equate to no less than 90 days of net imports (see Box 2.1). This basic oil stockholding obligation of IEA countries was first formulated in 1974 to establish "a common emergency self-sufficiency in oil supplies." In 2013, there were three net exporting IEA countries: Canada, Denmark and Norway. These countries do not have a stockholding obligation under the I.E.P. Agreement.

Of the 29 IEA countries, 20 countries also have minimum stockholding obligations as member states of the European Union (EU). A new oil stockholding EU Directive was adopted in 2009, which has brought the EU system closer in line with that of the IEA

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Box 2.1 IEA emergency reserve calculation: Minimum 90 days of net imports

The IEA minimum stockholding obligation is based on net imports of all oil, including both primary products (such as crude oil and natural gas liquids [NGLs]) and refined products. It does not cover naphtha and volumes of oil used for international marine bunkers.

The 90-day commitment of each IEA country is based on average daily net imports of the previous calendar year. This commitment can be met through stocks held exclusively for emergency purposes and stocks held for commercial or operational use, including stocks held at refineries, port facilities and in tankers in ports. The obligation specifies several types of stocks that cannot be counted towards the commitment, including military stocks, volumes in tankers at sea, in pipelines, at service stations or amounts held by end-consumers (tertiary stocks). It also does not include crude oil not yet produced.

Member countries can arrange to store oil outside of their national boundaries and include such stocks in meeting their minimum requirement. This option is particularly important for countries in which storage capacity constraints or supply logistics make domestic storage insufficient. To exercise this option and count the stocks held abroad towards the obligation, the governments involved must sign bilateral agreements assuring the viability of the stocks in an emergency.

When evaluating a country's compliance with the 90-day obligation, the IEA applies a 10% deduction to its total stocks, net any oil held under bilateral agreements. This accounts for any volumes that are technically unavailable (such as tank bottoms). (See "Annex C: Definitions and methodology" and www.iea.org/netimports.asp).

(see Annex D). For the majority of countries that are members of both organisations, the IEA and EU minimum stockholding obligations are now the same, with the additional requirement under the EU rules that at least one-third of the obligation be met with refined product stocks (the IEA stockholding requirement does not specify how the oil is to be held).

For a small number of countries, the minimum stockholding obligation is greater under the EU system than under that of the IEA, as the EU rules require countries to cover either 90 days of net imports or 61 days of consumption, whichever is greater. Thus net exporting countries (e.g. Denmark), or countries with relatively small levels of net imports compared to domestic consumption (e.g. Estonia, United Kingdom), are required to hold 61 days of consumption under the EU requirements compared to no obligation or only a minimal stockholding obligation under the IEA system.

Stockholding systems of IEA countries

Stockholding regimes vary across IEA countries, reflecting differences in oil market structure, geography and national policy choices related to emergency response. In the case of countries that are also members of the European Union, the stockholding policy reflects the need to comply with both systems. In general, there are three approaches to guarantee that overall stock levels meet minimum requirements: industry stocks, government stocks and agency stocks. Some countries use only one category of stockholding to meet the minimum obligation; most countries use a combination of categories.

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Stockholding structure

Industry stocks

Stocks held by industry, whether for commercial purposes or in order to comply with national stockholding rules, count towards meeting a country's IEA stockholding commitment. Most member governments require certain companies, such as importers, refiners, product suppliers or wholesalers, to hold a minimum number of days of stocks. Generally, the required amount is set in proportion to the company's oil import share or its share of sales in the domestic market. These obligated industry stocks are included in the overall industry stock levels reported for a country. IEA data on industry oil stocks, unless otherwise noted, are defined as all primary stocks on national territory, including stocks held by industry to comply with national emergency stockholding rules.

In 2013, 20 out of the 29 countries opted to meet all or part of their obligation by placing a stockholding requirement on industry. Of the 20 countries imposing minimum stockholding obligations on industry, six use this approach to meet the totality of their IEA obligation. They are Greece, Italy, Luxembourg, Sweden, Turkey and the United Kingdom. Norway has no IEA stockholding obligation as a net-exporter, however it places an obligation on companies that produce or import petroleum products in Norway to store product stocks corresponding to 20 days of normal consumption, which would then be used for emergencies. The following countries do not place such an obligation on industry: Australia, Canada, the Czech Republic, Estonia, Germany, Hungary, New Zealand, the Slovak Republic and the United States. Although these countries place no formal obligation on industry, their industry commercial stocks count towards the IEA obligation of 90 days of net imports.

Government stocks

Government-owned stocks are one of the means by which countries can ensure their IEA minimum stockholding requirement. These are typically financed through the central government budget and held exclusively for emergency purposes. In 2013, eight countries held government stocks: the Czech Republic, Ireland, Japan, the Republic of Korea, New Zealand, Poland and the United States.

Agency stocks

Some countries have a stockholding arrangement that involves establishing a separate agency endowed with the responsibility of holding all or part of the stock obligation. The agency structure and arrangements vary from country to country but in all cases are clearly defined by state legislation. Several countries have government-administered schemes (e.g. Belgium, Estonia, Finland, Hungary, Ireland, the Netherlands, Portugal and Spain). Others are industry-led and/or industry-owned entities (e.g. Austria, Denmark, France, Germany and the Slovak Republic).

Public stocks

The IEA refers to government and agency stocks as "public" stocks (including stocks held by industry-owned stockholding agencies). Such stocks have the advantage of providing a clear indication of oil available solely for emergency purposes. In recent years, the role of public stocks has increased noticeably in the overall emergency response potential of the IEA, both in terms of the number of countries holding public stocks and in the total volume being held.

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Table 2.1 Overview of oil stockholding systems in IEA member countries

	IEA membership	EU membership	Structure of stockholding responsibility
Australia	1979	-	-
Austria	1974	1995	Agency/industry obligation
Belgium	1974	1957	Agency
Canada	1974	-	-
Czech Republic	2001	2004	Government
Denmark	1974	1973	Agency/industry obligation
Estonia	2014	2004	Agency
Finland	1992	1995	Agency/industry obligation
France	1992	1957	Agency/industry obligation
Germany	1974	1957	Agency
Greece	1976	1981	Industry obligation
Hungary	1997	2004	Agency
Ireland	1974	1973	Agency
Italy	1974	1957	Industry obligation /(agency) *(from 2014)*
Japan	1974	-	Industry obligation/government
Korea, Republic of	2002	-	Industry obligation/government
Luxembourg	1974	1957	Industry obligation
Netherlands	1974	1957	Agency/industry obligation
New Zealand	1977	-	Government
Norway	1975	-	Industry obligation
Poland	2008	2004	Industry obligation/government
Portugal	1981	1986	Agency/industry obligation
Slovak Republic	2007	2004	Agency
Spain	1974	1986	Agency/Industry obligation
Sweden	1974	1995	Industry obligation
Switzerland	1974	-	Industry obligation
Turkey	1974	-	Industry obligation
United Kingdom	1974	1973	Industry obligation
United States	1974	-	Government

Note: unless otherwise indicated, all tables, figures and boxes in this chapter derive from IEA data and analysis.

In 2013, 19 out of the 29 IEA countries held public stocks. This compares to 10 out of 21 member countries in 1984. This increase reflects a rise in the number of countries with stockholding agencies, which has increased from 4 to 12 since the early 1980s. With the recently adopted changes to the EU minimum stockholding rules, Italy has recently decided to create an agency and a number of countries are currently considering establishing agencies (e.g. Greece, Luxembourg and the United Kingdom). This could further raise the number of member countries holding public stocks in the future.

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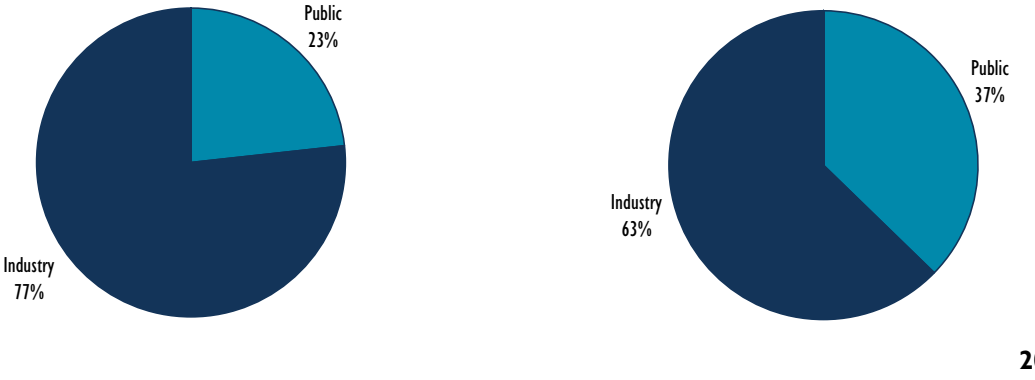
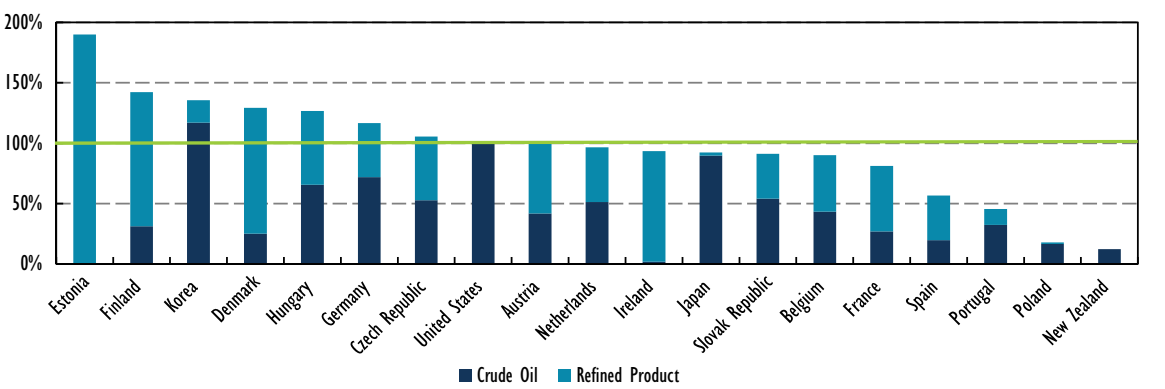
Figure 2.1 Industry versus public stocks as share of total IEA stocks



Source: IEA, 2014.

The relative portion of the minimum stockholding obligation covered by public stocks varies from country to country. In most cases, public stocks, including both crude and refined products, cover more than half of the country's minimum stockholding obligation. In other countries public stocks cover well beyond 90 days of net imports (see Figure 2.2). In some instances, this is because of declining net imports, resulting in a greater number of days' cover for a given volume of public stocks. In the case of Estonia, the IEA stockholding requirement in terms of net imports is substantially lower than the level of stocks the country must hold to meet its 61 days of consumption as a member of the European Union. Denmark also holds public stocks to meet its EU stockholding requirements; however, as a net-exporter, Denmark has no IEA minimum stockholding requirement.

Figure 2.2 Public stocks as a share of a country's IEA stockholding obligation



Note: public stock levels at end-June 2013; 100% = 90 days.
Source: IEA, 2014.

In ten IEA countries, public stocks are combined with a minimum stockholding obligation on industry. These include Poland, Portugal and Spain, where the proportion of public stock cover is lower compared to other public stockholding member countries. In these countries, the remainder of the IEA minimum requirement is met by stockholding obligations set on industry. In the case of New Zealand, while there is no stockholding obligation set on industry, the country relies on industry's commercial stocks to cover the bulk of its IEA minimum requirement and holds public stocks in the amount necessary to meet the remaining portion of the 90-day level.

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One general attraction of a mixed system, where both public stocks are held and a minimum obligation is set on industry, is that it can improve overall "visibility" of emergency stocks while maintaining an operational link with the oil companies. This should help to ensure rapid drawdown in an emergency. Nevertheless, there is no single, perfect system for maintaining the required minimum stockholding level. Any given stockholding arrangement will have both advantages and disadvantages in terms of efficiency, cost and equity. Ultimately, the choice will depend on the particular country's circumstances.

Box 2.2 Comparing stockholding arrangements

The arrangement for stockholding (industry, agency, or government, or any combination thereof) may differ from the way in which physical stocks are actually held. For example, obligatory industry stocks may be commingled with operational stocks, with the benefit of ensuring that stocks are ready for use – i.e. they are already "in" the supply chain. However, in some cases it can be difficult to distinguish between operational and obligatory stocks and thus difficult to monitor the stockholding obligation and the availability of these stocks in a crisis. By contrast, it is relatively easy to monitor stocks that are totally segregated from operational stocks (e.g. kept in separate emergency reserves or in single-purpose caverns). Segregation may add visibility to emergency stocks, but it may take longer to release such stocks into the market and, particularly in the case of refined products, it may require a programme of refreshing the volumes in order to maintain quality specifications. Another approach is to hold emergency stocks in tanks located within commercial tank farms, where the location of the volume of emergency stock can be pinpointed at any moment and made available during a crisis. This approach may offer the dual benefits of the held stocks being visible and easy to check, yet also readily available to be quickly brought into the operational system in times of emergency.

A large proportion of the total of IEA publicly held stocks is segregated, i.e. not commingled with industry operational stocks. This is principally because of the large volume of public stocks held in segregated underground salt dome formations in the United States. There are also substantial portions of public stocks held segregated in Belgium, the Czech Republic, Denmark, Hungary and the Slovak Republic (see Table 2.2). Segregated public stocks have the benefit of being highly visible and thus injecting a sense of stability into the market.

Crude oil versus product stocks

The IEA stockholding obligation does not specify whether stocks should be held in the form of crude or refined oil. IEA countries that also belong to the European Union typically hold product stocks based on EU regulations which require that at least one-third of the obligation be covered by product stocks.

The choice between holding reserves in either crude oil or refined products will depend on specific factors in each individual member country. One factor is the financial burden of storage, which can be significantly higher for refined products than for crude oil. Countries with a large refining industry will likely hold more crude oil, which provides greater flexibility in times of crisis. In countries that have limited domestic refining capacity or rely on product imports to meet a large share of domestic demand, there is a greater tendency to hold reserves of refined products.

As of 2013, total oil stocks in IEA countries (including both volumes held exclusively for emergency purposes and those held for commercial or operational use) were weighted towards crude (60%) over petroleum products (40%). This reflects the large volumes

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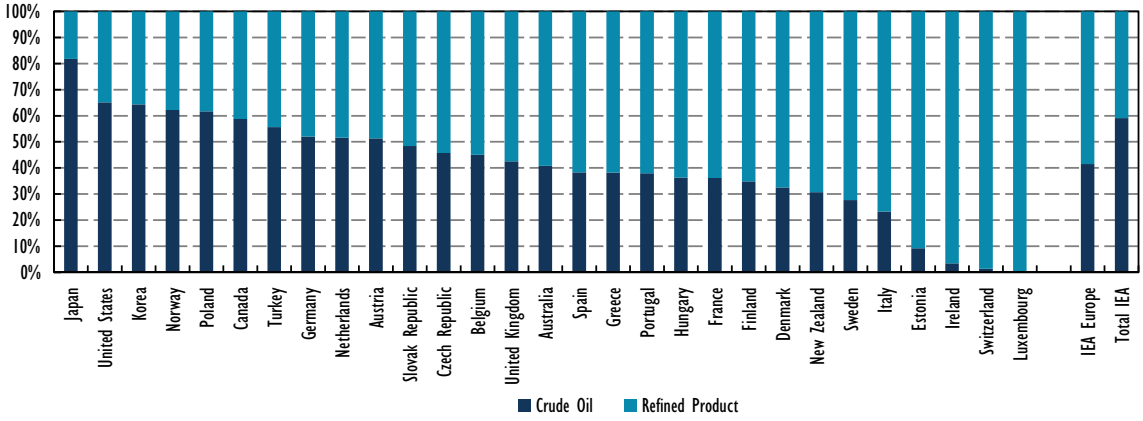
Figure 2.3 Total oil stocks by product and crude, 2013



Note: total public and industry stock levels at end-June 2013; country results include stocks held abroad to meet IEA obligation.
Source: IEA, 2014.

of crude in the Strategic Petroleum Reserve (SPR) in the United States and Japan's government-owned stocks managed by Japan Oil, Gas and Metals National Corporation (JOGMEC). In IEA Europe, the split was reversed, with just over 40% crude and nearly 60% in petroleum products – a direct result of the EU obligation to hold product stocks. Significant differences are also evident from country to country. At one end of the spectrum, Japan holds over 80% of its stocks as crude (nearly all government-owned stocks managed by JOGMEC are crude oil). Similarly, the US government holds all but a fraction of its public stocks in the form of crude oil, while industry holds the majority of its stocks in products. In contrast, Luxembourg and Switzerland hold all or virtually all their stocks in products: the former has no refineries; the latter has only two refineries. To make up for this limited (or complete lack of) refining capacity, both countries have industry-only stockholding arrangements that require product importers to stock a given percentage of their imports.

Location and availability

In specific instances, member countries are able to count stocks held in the territory of other countries in order to fulfil their minimum stockholding requirements. This can include stocks held in other countries for logistical purposes, such as at a neighbouring country's port where volumes are unloaded and delivered by pipeline (e.g. the Italian port of Trieste for Austrian stocks). Stocks counted towards the minimum obligation can also include those held under bilateral agreements between governments, which guarantee access to such stocks during a crisis. This creates efficiencies in stockholding, especially for countries with insufficient storage capacity or in which a major demand centre is located on or near an international border.

Interconnectivity of the oil market infrastructure can also facilitate spare storage capacity or more cost-effective storage by utilising capacity in neighbouring countries. This flexibility is often an important means of enabling industry participants to meet stockholding obligations imposed by the government. In some cases, the stocks held abroad are actually owned by the company or agency with the stockholding obligation. In other cases, the company or agency does not own the stocks but has the right – based on short-term lease contracts or tickets – to purchase them in a crisis (see Box 2.3).

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Most IEA countries allow the use of such bilateral stockholding arrangements to meet the IEA minimum stockholding obligation. At the same time, many countries impose a limit on the share of stock obligations that can be held abroad – normally up to maximum of about 10 to 30% of actual stocks. Some countries prohibit completely the holding of emergency stocks in other countries (see Table 2.2).

Table 2.2 Public and obligated industry stockholding practices in IEA member countries

	Segregated/commingled	Possibility of holding stocks in another country (location)
Australia	N/A	No existing bilateral agreements
Austria	ELG commingled	Not allowed (with exception of stocks at Trieste oil terminal, Italy)
Belgium	APETRA stocks partly segregated	30% maximum (FR, DE, IR, LV, NL, UK)
Canada	N/A	No existing bilateral agreements
Czech Republic	ASMR crude segregated; small proportion of products commingled	Allowed (DE, SK), but not in form of tickets
Denmark	FDO mostly segregated; obligated industry stocks commingled	10% maximum (EE, FI, IR, LV, NL, SW, UK)
Estonia	OSPA commingled	Allowed (DK, SW, FI)
Finland	NESA segregated; obligated industry stocks commingled	NESA not allowed; 20% maximum of obligated industry stocks (DK, EE, LV, SW)
France	SAGESS partly segregated; obligated industry stocks commingled	10% maximum (small amount of SAGESS stocks held in BE, DE, NL)
Germany	EBV partly segregated	10% maximum (BE, FR, IT, NL)
Greece	Obligated industry stocks commingled	Allowed in EU countries but no bilateral agreements are concluded with other IEA countries
Hungary	HUSA segregated	Not allowed
Ireland	NORA partly segregated	Allowed (BE, DK, FR, NL, SW, UK)
Italy	Obligated industry stocks commingled	Allowed (DE, DK, EE, HU, MT, NL, SI, CY*)
Japan	Government crude stocks segregated while its products stocks are commingled; obligated industry stocks commingled	Not allowed
Korea, Republic of	KNOC partly segregated; obligated industry stocks commingled	Not allowed
Luxembourg	Obligated industry stocks commingled	Allowed (BE, DE, FR, NL)
Netherlands	COVA partly segregated; obligated industry stocks commingled	Allowed (amounts of COVA stocks held in DE, SW, BE)
New Zealand	Ticketed volumes commingled	Allowed (AU, DK, JP, NL, UK)
Norway	Obligated industry stocks commingled	No existing bilateral agreements
Poland	ARM segregated; obligated industry stocks commingled	No existing bilateral agreements
Portugal	Obligated industry stocks commingled	10% maximum for obligated industry, 20% maximum for total national obligation (DE, EE, NL)
Slovak Republic	Segregated	Allowed (CZ), but not in form of tickets
Spain	CORES partly segregated, obligated industry stocks commingled	Allowed (FR, IT, PO)
Sweden	Obligated industry stocks commingled	20% maximum (DK, EE, FI, IR, NL, UK)

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Table 2.2 Public and obligated industry stockholding practices in IEA member countries *(cont.)*

	Segregated/commingled	Possibility of holding stocks in another country (location)
Switzerland	Obligated industry stocks commingled	Not allowed
Turkey	Obligated industry stocks commingled	Not allowed
United Kingdom	Obligated industry stocks commingled	Allowed (BE, DK, FR, IR, NL, SW)
United States	SPR segregated	No existing bilateral agreements

Notes: AU=Australia; BE=Belgium; CY=Cyprus[1,2]; CZ=Czech Republic; DE=Germany; DK=Denmark; EE=Estonia; FI=Finland; FR=France; HU=Hungary; IR=Ireland; IT=Italy; JP=Japan; LV=Latvia; MT=Malta; NL=Netherlands; PO=Poland; SI=Slovenia; SK=Slovak Republic; SW=Sweden; UK=United Kingdom; No industry obligation/no public stocks.

1. Footnote by Turkey
   The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of United Nations, Turkey shall preserve its position concerning the "Cyprus issue".
2. Footnote by all the European Union member states of the OECD and the European Union
   The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

Stocks held abroad under bilateral agreements can be either in the form of volumes owned or amounts leased as tickets. In practice, the proportion of stocks held abroad is generally small for the IEA as a whole – less than 3% of total stocks. However, it can represent a significant portion of stock cover for some member countries. Because of insufficient domestic storage capacity, Luxembourg has as much as 88% of its stockholding obligation abroad. Some other IEA countries also hold a relatively high proportion of their stockholding obligations abroad (see Figure 2.4).

Box 2.3 Stockholding tickets

Many IEA countries give oil companies or stockholding agencies the choice of meeting their stockholding obligations in two ways: either by owning physical stocks themselves or, for certain amounts, arranging stock cover through leasing agreements, referred to as "tickets".

Tickets are stockholding arrangements under which the seller agrees to hold (or reserve) an amount of oil on behalf of the buyer in return for an agreed fee. The buyer of the ticket (or reservation) effectively owns the option to take delivery of physical stocks in times of crisis, according to conditions specified in the contract.

Tickets can be issued for either crude or refined products; the agreement specifies the quantity, quality and location of the oil for a specified period (typically a calendar quarter). Tickets can be either domestic contracts or contracts between entities in separate countries (the latter must be within the framework of a bilateral government agreement).

The rationale behind oil stock tickets is that a company holding stocks in excess of its obligation can offer such stocks to cover the obligation of another company or agency, either domestically or abroad. Tickets are sold mainly by refiners with excess inventory as a way to offer compulsory stock obligation cover to third-party buyers. In some cases, a company in one country may provide tickets to one of its own affiliates that operates in another country. In all cases, the ticket seller is prohibited from counting the oil in question towards its own stockholding obligation.

Ticketing is a flexible and, generally, cost-effective way for companies or agencies with insufficient stocks to avoid being in breach of stockholding obligations. It essentially provides an alternative to acquiring oil stocks directly and building and/or renting necessary storage capacity.

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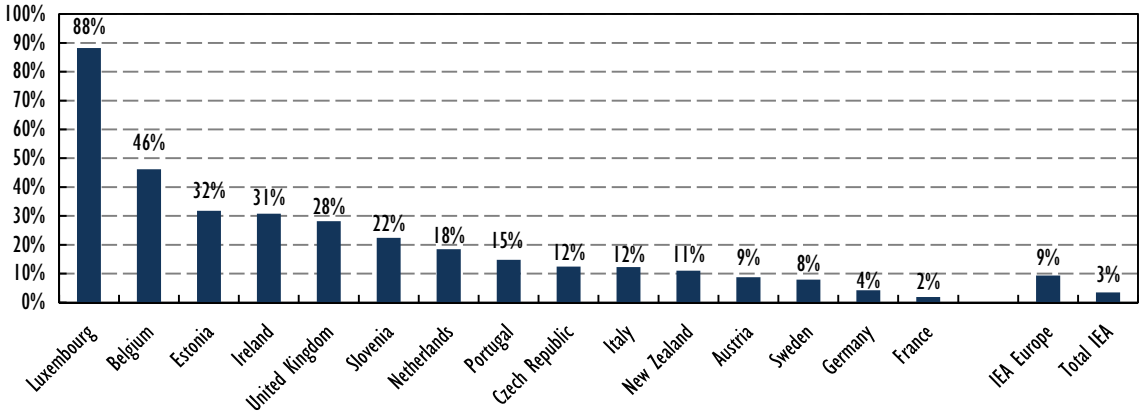
A large part of the stocks held abroad is in the form of ticket arrangements. The use of tickets is quite common in IEA Europe, because, based on the common market, major oil companies see Europe as a whole or as several large regions. They recognise an opportunity to use cross-border ticket agreements with different countries to optimise their stocks in relation to their obligations. Nevertheless, several IEA countries specifically prohibit such stockholding ticket arrangements, including Austria, the Czech Republic, Greece, Hungary, Japan, the Republic of Korea, Norway, the Slovak Republic, Switzerland and Turkey.

Figure 2.4 Countries with stocks held in other countries (percentage of total stocks)



Note: Includes stocks held in other countries for logistical purposes, destined for import, and stocks held under bilateral government agreements, including volumes under ticket contracts; stock levels at end-June 2013.
Source: IEA, 2014.

Decision process for an IEA collective action

IEA emergency response measures are set in motion following an IEA Governing Board decision, once a significant supply disruption occurs or is likely to occur in the very near future. Based on IEA analysis of the situation, the IEA executive director informs IEA countries (via the Governing Board) of this assessment and specifies whether or not activation of the emergency response measures is desirable. If action is recommended, the executive director will suggest a volume of oil equivalent to be made available to the market by IEA countries. Each country's share in the action is then based on its share of total IEA oil consumption. Members have a short period to react to this assessment. Official notice of activation of emergency response measures is given by the executive director.

Once there is a decision to activate emergency measures, the proceedings in member countries essentially move through three stages:

- Governments decide the details of their contribution, including volume, timing, method (one measure or a combination of measures) and source of the stock release (government/agency stocks versus obligated industry stocks).
- Member countries draw up legislative decrees or make public postings detailing the actions to be taken and the necessary procedures (e.g. the release of public stock through tender, the lowering of stockholding obligation set on industry).
- Once the relevant legislative powers are activated, action is initiated for the offering of stocks to the market.

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In most IEA countries, the length of time required to move through these three stages – i.e. from deciding to act to the release of stocks – is two to seven days. Once the stock release procedures have been carried out, the actual physical delivery of stocks to the market can take from one day to as much as three weeks, depending on the emergency stocks structure. In the case of member countries that hold a significant proportion of emergency stocks overseas, the actual physical availability of those stocks in the country itself could take up to six weeks. Such countries may opt instead to swap stocks with another country, which can significantly reduce this period.

Box 2.4 The evolution and flexibility of the I.E.P. Agreement

The 1974 I.E.P. Agreement established IEA emergency response mechanisms to create a concrete and co-operative action plan in the event of a major disruption in oil supply. The I.E.P. Agreement outlines four key response measures: release of stocks; restraint of demand; switching away from oil to other fuels; and increasing domestic oil production. In support of the first measure (release of stocks), the agreement requires that IEA countries hold in reserve oil stocks equivalent to at least 90 days of net oil imports.

IEP measures were initially designed to take effect in the event of oil supply disruptions involving a loss of 7% or more of normal oil supply, either for the IEA as a whole or any individual member country. However, as oil markets have evolved, so have the tools of the IEA for responding to supply disruptions. Today's reality calls for greater flexibility in determining how and when to resort to emergency measures.

The IEA established the Co-ordinated Emergency Response Measures (CERM), a series of actions that provide a rapid and flexible system of response to actual or imminent oil supply disruptions. CERM measures emphasise and enable the early release of stocks.

Stock drawdown

The exact method of emergency stocks release varies considerably among IEA countries. In practice, the preferred approach in most countries that impose all of the stockholding obligations on industry operators is a uniform reduction in the stockholding obligation by a certain percentage or by a specified number of days of supply. In general, these volumes are made available through the normal channels at market prices. By contrast, Luxembourg convenes a committee of government/industry representatives to determine the release and pricing of obligatory stocks. In Switzerland, the release would be allocated according to individual company needs.

A variety of approaches is also used for the release of government/agency stocks. Several countries would conduct the release from public stockholdings through a tender bidding process (Germany, Japan, the Netherlands, Poland and the United States). Most other countries would make the stock available at prevailing market prices (the Czech Republic, Estonia, Finland, France, Hungary, Ireland, New Zealand, Portugal and Spain). In the Republic of Korea, the government determines the pricing of the release from its stockpile. The Czech Republic, Finland and the United States are examples of countries that sometimes release public stocks in the form of loans.

Financing and fees

The way in which emergency stocks are financed will largely depend on the stockholding system used (e.g. obligated industry stocks or public stocks; government based or industry-based stockholding agency).

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Box 2.5 Costs, benefits and financing of holding emergency oil stocks

In order to assist non-IEA countries which are considering establishing oil stockholding systems for dealing with supply disruptions, the IEA has published a paper that draws together analysis of the costs and benefits of emergency stocks, in addition to exploring options for financing the establishment of these stocks (IEA, 2013).

With regard to benefits, emergency oil stocks primarily function like an "insurance" against oil supply disruptions. Significant economic benefits are derived primarily from offsetting oil supply losses and thereby reducing potentially significant oil price increases. These consist of reduced GDP losses and reduced import costs. Using a model to simulate tens of thousands of possible oil supply disruption scenarios and market outcomes, the paper estimates that global net benefits derived from existing emergency stocks amount to USD 41 per barrel per year. This figure equals some USD 3.5 trillion over a 30-year period considered in the paper. This represents a conservative estimate of global benefits, as it does not include benefits derived from mitigating domestic or product supply disruptions; these are highly country-specific and depend to a large extent on the local context. For example, the benefits obtained during domestic disruptions not only depend on the size and duration of the disruption, but also on the location of emergency stocks.

The cost of stockholding depends on the size and type of storage facilities (aboveground tanks or underground caverns) as well as the composition of stocks (crude oil or petroleum products). Total yearly costs range from USD 7 to USD 10 per barrel, reflecting the fact that holding emergency stocks in underground caverns is about 30% cheaper than holding oil in aboveground facilities. The acquisition of stocks represented at least 50% and up to 85% of the overall costs, based on oil price levels at the time of the study. The expenditures for building the storage facilities and the related infrastructure amount to up to one-fifth of yearly costs. The share of expenses for operating and maintenance of the storage sites varies considerably between storage options, amounting to as little as 5% for caverns and as much as 25% for aboveground facilities. Refreshment of oil products and land costs both represent a marginal proportion of overall costs.

There are several ways of financing the acquisition and maintenance of emergency oil stocks as reflected in the distinct practices adopted by IEA countries. Financing mechanisms can generally be divided into two categories: financing of public stocks and financing of obligated industry stocks. The different approaches highlight the flexibility in financing emergency stocks and reflect efforts to keep the burden on the state budget, industry and final consumers at a minimum. In many countries, the cost to the final consumer amounts to less than USD 0.01 per litre of fuel.

In the case of countries imposing stockholding obligations on industry, the associated costs are imposed on companies through minimum requirements usually set in proportion to a company's oil import share or its share of sales in the domestic market. The stockholding obligation for refineries is set higher in some countries (Italy, Turkey and the United Kingdom) because of their high level of operating stocks. Ultimately, the costs of obligated industry stocks are borne by the final consumers. Of the 20 countries imposing a stockholding obligation on industry, only three (Japan, Luxembourg and Switzerland) have schemes in place to provide companies with financial support to offset the costs of holding obligated stocks.

In the case of public stocks, an important differentiation must be made between the initial set-up/capital costs and the running costs associated with the government/agency stockpiles. In both cases, the financing methods vary across the 19 IEA countries which hold public stocks.

In several IEA countries with government-held stockpiles or stockholding agencies, the initial set-up/capital costs of the stockpile were financed from the central government budget (the Czech Republic, Estonia, Finland, Japan, Republic of Korea, Poland, the

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Slovak Republic and the United States). Funds from the central budget also financed New Zealand's purchase of stock tickets. By contrast, in the other ten IEA countries with public stocks, the initial establishment of the emergency stocks was financed through bank loans or in the form of bonds issued by the stockholding agency. In the cases of Austria, Germany, Hungary and the Netherlands, government loan guarantees were used in the initial set-up phases to allow the agencies to borrow at lower interest rates on financial markets.

The running costs of the public stockholding agencies are typically financed through one of three principal methods: from the central government budget, through a levy paid by market operators or through a direct tax paid by final consumers. In six IEA countries, running costs are financed through the central government budget (the Czech Republic, Japan, the Republic of Korea, New Zealand, Poland and United States). In most other IEA countries with stockholding agencies, the running costs are recouped either through a fee (levy) paid by market operators directly to the agency or via a tax imposed on final consumers by central governments which is then passed on to the stockholding entity.

Table 2.3 Financing for government/agency stocks

	Initial set-up costs			Running costs		
	Government budget	Government-backed loan	Bank loans/ bonds	Government budget	Levy on industry	Tax
Austria		X			X	
Belgium			X		X	
Czech Republic	X			X		
Denmark*			X			
Estonia	X				X	
Finland	X					X
France			X		X	
Germany		X			X	
Hungary		X			X	
Ireland			X		X	
Japan	X			X		
Korea	X			X		
Netherlands**		X				X
New Zealand***				X		
Poland	X			X		
Portugal			X		X	
Slovak Republic	X			X		
Spain			X		X	
United States	X			X		

* In Denmark running costs are covered by the financial surplus the Danish stockholding agency built up in the early 1990s in the wake of falling demand and rising indigenous output, together with the amortisation of storage facilities.
** In the Netherlands running costs are covered by a levy on final consumers.
*** New Zealand has not built up a physical reserve for emergencies. The difference between operating industry stocks and the IEA obligation is entirely covered by stockholding tickets. Therefore, there have been no set-up costs.
Source: IEA, 2013.

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In general, the levy is charged to market operators, such as refiners, importers and producers, according to the volume of product sales and deliveries into the domestic market (Belgium, Germany, Ireland, Portugal and Spain), on crude/product import volumes (Hungary, Portugal), or on the volume to be stored (Austria). In all cases, the final consumer bears the costs covered by the fee via retail prices. Denmark discontinued its levy in 1992 after finding that the stockholding agency could cover running costs from a considerable financial surplus built up in previous years. France covers the costs of obligatory stocks through a monthly fee charged to industry by the Professional Committee for Strategic Petroleum Stocks (CPSSP), the organisation responsible for ensuring that national stockholding obligations are met. In Austria, the storage agency *Erdöl-Lagergesellschaft* (ELG) is financed by annual storage fees charged to companies.

Other response measures

In addition to stockdraw, IEA countries have at their disposal a number of tools that can be used on their own or in combination with stockdraw during a co-ordinated action. Surge production, similarly to stockdraw, increases the supply of oil on a short-term basis, while demand restraint and fuel switching are both designed to help temporarily curb the use of oil. In some instances, IEA countries may take other, temporary, emergency response measures in order to help oil markets rebalance supply and demand during a disruption.

Surge production

IEA countries with domestic oil production may be able to raise indigenous production for a short period of time in order to increase available supplies in a crisis situation. This measure is limited to member countries with significant levels of production. The potential volume available in a crisis is dependent upon the amount of spare production capacity maintained in the country. The extent of such capacity would depend on particular circumstances and would be constrained by the need to maintain good oil-field practices.

The IEA considers the aggregated capacity of its member countries to increase oil production to be insignificant, as producers generally maximise production rates and do not maintain stand-by spare production capacity. However, during a disruption, member country governments may take steps to facilitate bringing on line any additional production possible. This can include temporarily relaxing regulations that may apply in normal times, primarily for oil-well safety conditions. Typically, such surge production can only be achieved over a short period of time (e.g. a number of months) and carries the risk of damaging wells and reservoirs.

Demand restraint

Demand restraint measures aim to rapidly reduce oil consumption in a crisis. This can be done, over short periods of time, either by reducing the amount of oil actually used or by limiting the amount of oil supply available to consumers. In both instances, the degree to which measures are applied can range from light-handed (such as public information campaigns to promote voluntary actions) to more medium and heavy-handed compulsory measures (such as driving restrictions or fuel rationing).

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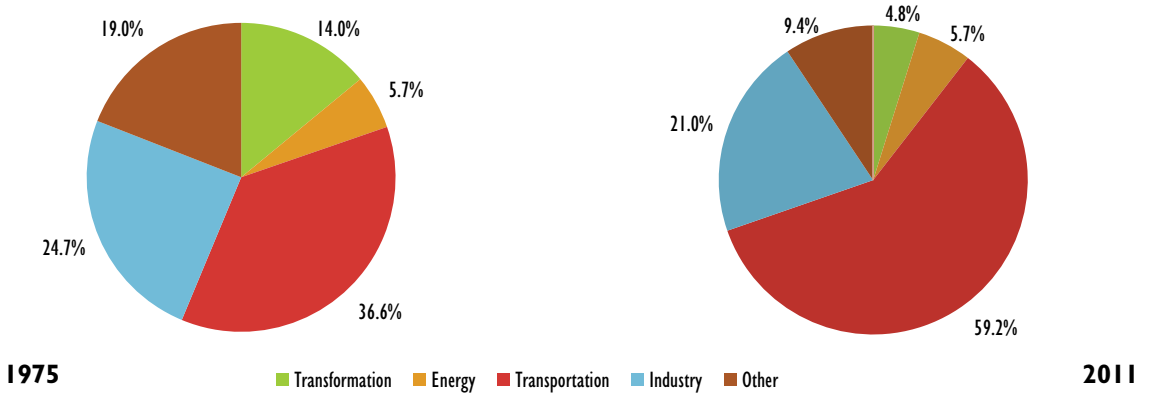
Figure 2.5 Oil consumption by sector in IEA countries

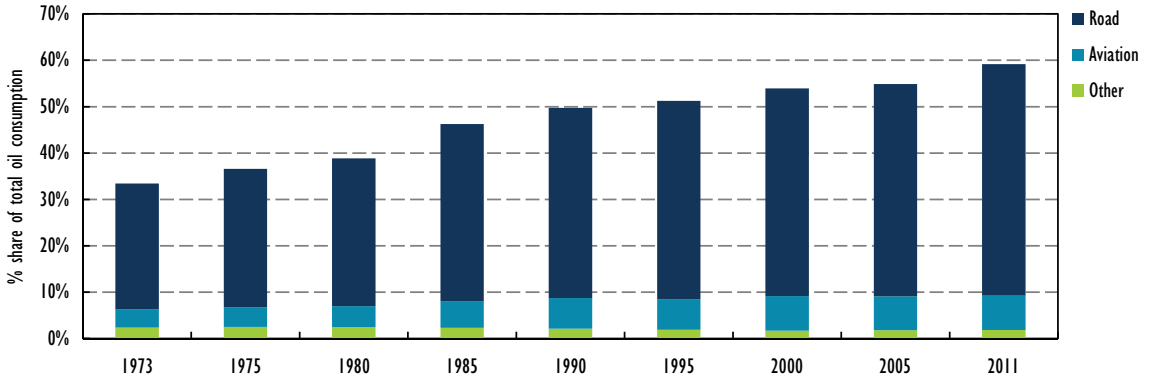


Source: IEA, 2014.

Demand restraint measures are not limited to a specific sector of consumption. For example, oil use in the industry sector could be cut by limiting the operating times of particular segments of industry that have high levels of oil consumption. Measures to reduce oil consumption in the "other sectors" (which include residential use) could include encouraging residents of homes with oil heating to lower the thermostat in winter.

The transportation sector warrants special attention. Demand for oil in the transportation sector has grown steadily over the past 30 years, both in terms of volume and share of total oil demand. In addition, the IEA expects transportation to account for nearly all future growth in oil demand. Currently, transportation consumes more than half of all oil used in IEA countries. This includes all transport activities, such as aviation, road, rail and other modes, such as inland water navigation. Because road transportation represents roughly 85% of all oil consumption in the transport sector and offers the greatest potential for reductions during a crisis, many short-term measures to cut back on oil demand during a crisis tend to focus on road transportation.

Figure 2.6 Transport sector share of total oil consumption (total IEA), 1973-2011



Source: IEA, 2014.

Saving oil: Focus on road transportation

In general, there are two types of policy approaches to reducing oil usage in road transportation. One approach focuses primarily on providing people with less energy-intensive travel options to reduce fuel consumption. These options tend to offer people

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more choices in transportation, such as better or cheaper public transit, carpooling, or the promotion of "eco-driving" (efficient driving styles and vehicle maintenance steps). They may also reduce oil consumption through options that reduce the need for transportation generally (such as promoting telecommuting [working from home] and compressed work weeks) or that avoid driving in peak traffic hours (such as flexible work schedules).

The second policy approach is more restrictive in nature, essentially limiting travel options or requiring shifts in behaviour. This approach includes measures such as driving bans, mandatory carpooling, speed limit reductions or forced changes in work schedules. More restrictive options tend to result in greater estimated reductions in fuel consumption. However, they may also be more "expensive" to society and unpopular – and, therefore, less politically feasible.

Most light-handed demand restraint measures are relatively inexpensive to implement, mainly requiring a good public information campaign with related support through the

Box 2.6 Examples of transport demand restraint measures

- Eco-driving includes a wide array of behavioural changes such as more efficient driving styles (e.g. changes in acceleration/deceleration and gear shifting patterns), optimal tyre inflation, reducing vehicle weight and other steps. An aggressive and comprehensive public information campaign on the benefits of eco-driving could yield substantial fuel savings. Some countries already run information campaigns of this type at least occasionally; stronger efforts could generate much better compliance, especially during emergencies.
- Telecommuting and flexible work schedules can save substantial fuel and can potentially be implemented very quickly. A well-organised "emergency telecommuting" programme could yield large reductions in fuel use, particularly if employers agree in advance to participate and designate certain employees to telecommute during predefined situations.
- Measures to increase carpooling, if successful, can provide rapid, large reductions in oil demand. However, success may be very dependent on the level of incentives given to drivers, which could make this option quite costly. Restrictive options that require carpooling (such as restricting certain traffic lanes to carpools) are likely to be most effective, but may be seen as inequitable unless relatively limited in application. Programmes focused only on provision of information (such as setting up a website to help potential car poolers find each other) will likely be more popular, but less effective.
- Restrictions on driving, such as odd-even licence plate driving bans, can potentially lead to very large savings. However, they may restrict mobility much more than some other measures and, therefore, will be unpopular. Multiple-vehicle households tend to be less affected by this type of policy, which may make this option seem less equitable than some others. If conducted over longer periods, the effectiveness of such policies may decline as travellers develop strategies to work around the regulations.
- Reducing speed limits on motorways can be very effective for saving fuel, particularly because cars and trucks use much more fuel per kilometre as speeds increase above 90 km/h (about 55 mph). However, success depends on an adequate enforcement regime. Providing clear information to the public regarding the strong links between lower speeds and fuel savings may help increase compliance during an emergency. An appropriate infrastructure must be put in place ahead of time (such as variable speed limit signs) to support rapid change of posted speed limits.
- More information on demand restraint measures can be found in the IEA publication *Saving Oil in a Hurry* (IEA, 2005)

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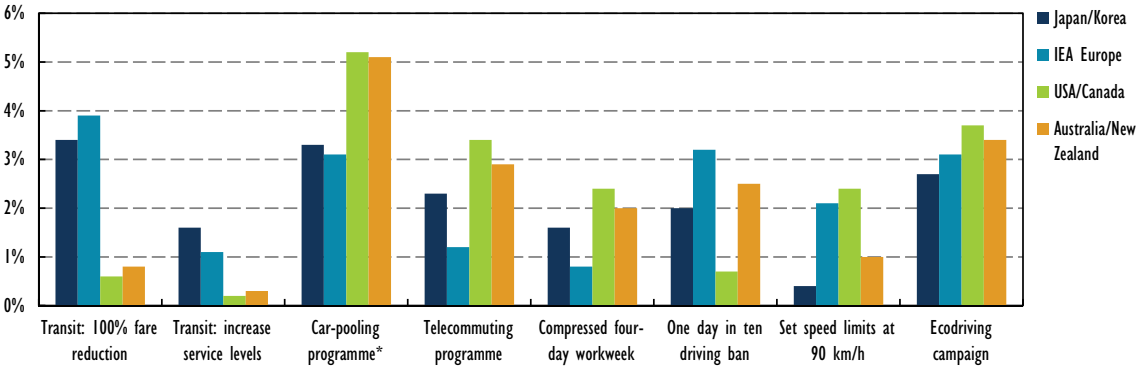
development of websites or other outreach programmes. In some cases, these measures will provide only modest oil savings. However, an aggressive and successful programme can result in significant fuel savings – up to 1 mb/d across all IEA countries. Public support for certain measures, such as promotion of eco-driving, is likely to be quite good. In fact, these might be good measures to implement at any time and on a permanent basis, although their impact may be highest in an emergency situation, when the public is most likely to be responsive.

The more restrictive, mostly heavy-handed measures described above may be most effective during the early stages of an oil emergency to help avoid "panic" behaviour, such as fuel hoarding. However, harsh control measures that restrict fuel purchases or directly restrict driving – particularly without providing travel alternatives – will ultimately be very unpopular and expensive for countries. In addition, they are likely to be difficult to maintain for any length of time.

Regional differences in potential savings

The estimated effectiveness of the available demand restraint measures varies significantly among geographical regions of IEA countries. This reflects regional variations within the transport sector itself, particularly in terms of the proportion of different travel modes and the resulting flexibility of travellers to change modes during a time of crisis.

Figure 2.7 Percentage reduction in total petroleum fuel use for selected measures, by IEA region



* When infrastructure is in place.
Source: IEA, 2005.

The extent of public transit infrastructure is one example of the difference in flexibility of the existing transportation systems. IEA countries in Europe, Japan and the Republic of Korea tend to have more highly developed public transit and lower levels of car ownership as compared with Canada and the United States, or Australia and New Zealand. As a result, measures to increase transit ridership in Europe, Japan or the Republic of Korea result in significantly larger reductions (by percentage) of petroleum use, relative to the other countries. Conversely, carpooling policies appear less effective in Europe and most effective in North America and in Australia and New Zealand, where levels of solo driving are relatively higher. Thus, the latter countries derive a greater benefit from increased carpooling.

The potential of telecommuting and flexible work policies is smallest in Europe, relative to other regions. Current levels of solo car driving for commute trips in Europe are already relatively low. Thus, the benefit of telecommuting or flexible work schedule policies is relatively greater in those countries that have more solo car commute trips.

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Driving bans appear most effective in Europe and least effective in North America. In this case, the difference is a function of the relative levels of household car ownership. Average car ownership per household is highest in North America, which means that households are more likely to have at least one car available on any given day that a driving ban is enforced (such bans are usually set by licence plate number).

Speed limit reduction and enforcement policies appear most effective in Europe and North America, where there is relatively higher motorway usage and, in the case of Europe, higher maximum speed limits. Thus, relative to other IEA countries, Europe and North America derive greater benefit from a speed reduction.

Table 2.4 Oil-saving effects of measures, summed across all IEA countries

Potential oil savings by category, if implemented in all IEA countries	Measure
VERY LARGE More than 1 million barrels/day	**Carpooling:** Large programme to designate emergency carpool lanes along all motorways; designate park-and-ride lots; inform public and match riders.
	Driving ban: Odd/even licence plate scheme; provide police enforcement; appropriate information and signage.
LARGE More than 500 000 barrels/day	**Speed limits:** Reduce highway speed limits to 90 km/h; provide police enforcement or speed cameras, appropriate information and signage.
	Transit: Set fares for public transit at zero.
	Telecommuting: Large programme, including active participation of businesses; public information on benefits of telecommuting; minor investments needed in infrastructure to facilitate.
	Compressed work week: Programme with employer participation; public information campaign.
	Driving ban: One in ten days based on licence plate; provide police enforcement and signage.
	Eco-driving: Promote efficient driving styles and vehicle maintenance steps, intensive public information campaign.
MODERATE More than 100 000 barrels/day	**Transit:** Reduce current public transit fares by 50%.
	Transit: Increase weekend and off-peak transit service; increase peak service frequency by 10%.
	Carpooling: Small programme to inform public, match riders.
SMALL Less than 100 000 barrels/day	**Bus priority:** Convert all existing carpool and bus lanes to 24-hour bus priority usage; convert some other lanes to bus-only lanes.

Source: IEA, 2005.

Fuel switching

Fuel switching is another measure that IEA countries can employ in order to contribute to a collective emergency response. Switching away from oil into other energy sources reduces the use of oil, thereby making additional supply available to the market.

The role of oil in economic sectors has changed significantly since the creation of the IEA, consequently reducing the scope for rapidly switching away from oil during a disruption. The share of oil in the overall energy supply mix of IEA countries has dropped from 54% to around 35%, reflecting increased use of natural gas and the development of nuclear energy replacing oil in electricity generation. In 1973, oil was used for 26% of the total electricity generated in all IEA countries; by 2012, this share was roughly 3%.

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Oil use has also changed, becoming increasingly concentrated in the transportation sector and within the industry sector in the petrochemical industry. In both cases the potential for fuel switching is limited. The share of all oil being used for heat and power generation has decreased significantly, from a peak of around 30% in 1973-74 to less than 7% in 2011 (less than 3 mb/d). Short-term fuel switching is only truly possible within these two sectors; thus, its potential to be effective in a time of crisis is likely to be less effective.

Examples of IEA co-ordinated actions illustrate a significant change in fuel switching as a potential emergency response measure in an oil supply disruption. In 1991, IEA countries decided to activate a contingency plan to address a possible oil supply shortfall during the First Gulf War by making 2.5 mb/d of oil available to the market. Approximately 2.7% of the total volume (67 kb/d) was to come from fuel switching. In the IEA collective actions in 2005, following Hurricane Katrina, and in 2011, in response to disrupted supplies from Libya, none of the oil made available came from fuel switching.

Other short-term emergency response measures

In some instances, IEA countries may seek to provide additional flexibility during a crisis in order to help rebalance supply and demand, through the temporary relaxation of specific regulations. This can be in the form of relaxing product quality specifications for a limited period of time, such as allowing winter fuel grades to be used out of season, in order to rapidly increase supplies available to consumers in a crisis. Both Austria and the United States have the ability to take such emergency measures, the latter having done so as recently as October 2012 in the aftermath of Hurricane Sandy.

Another example of providing greater flexibility to markets in response to a crisis is the relaxation of regulations regarding where emergency oil stocks are held. In both France and Spain, requirements for emergency oil stocks to be proportionally distributed across the country can be relaxed in order to allow for a geographical exchange, where emergency stocks in one area are swapped with commercial stocks held elsewhere in the country. This allows for emergency stocks to be used to help re-establish regional imbalances in supply and demand, while maintaining the country's overall emergency stockholding level. While not intended as a means for contributing to an IEA collective action, such flexibility measures can be particularly useful for dealing with regional or local disruptions.

Concluding remarks

The measures described in this chapter are the primary means through which IEA countries participate in a collective response during a short-term oil supply disruption. Each country determines which emergency response measures are most appropriate, depending on their domestic market conditions. IEA countries can take different measures in a co-ordinated manner, relying on a single measure or a combination of several measures. Chapter 4, entitled "Emergency response systems of individual IEA countries", describes in detail the oil infrastructure and emergency response policies of individual IEA countries.

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Natural gas security in IEA countries

Introduction

Energy markets have changed substantially since the creation of the International Energy Agency, and policy makers in IEA member countries today recognise that energy security is represented by more than just oil supply. Natural gas is playing an ever-growing role in the energy balances of IEA countries, making gas security a key element in energy security. Unlike the case of oil, however, there is no framework for taking collective action in response to a natural gas disruption, and IEA countries do not have the equivalent treaty requirements to establish emergency response mechanisms for natural gas. Instead, each IEA country agrees to review its gas emergency response policy, to share best practices and to explore together ways to reinforce gas security, individually and collectively.

Assessing a country's exposure to a possible gas disruption, as well as its ability to respond in such a crisis, was an integral part of the most recently completed cycle of Emergency Response Reviews (ERRs). The mechanisms and policies of individual IEA countries for responding to gas emergencies are described in the country profiles provided in Chapter 4. This chapter provides an overview of key issues related to gas security and of the emergency response policies in IEA countries.

The growing role of gas in energy security

Natural gas has been seen as a secure fuel for many decades. As historically most gas was sourced close to consumption centres, inter-regional trade was relatively small, and supplies were primarily transported by pipelines based on long-term contracts. Despite recurrent political tensions, European markets were well supplied. Transit issues, in particular, were rarely troublesome. Likewise, liquefied natural gas (LNG) supplies to Japan and the Republic of Korea have been very stable for many years.

Several considerable changes have taken place since, which give greater importance to the inclusion of gas in energy security policies. First, the share of natural gas in the total primary energy supply (TPES) of IEA countries has increased considerably, from 19% in 1973 to 26% in 2012, as natural gas has become the fuel of choice for electricity production. This was particularly the case in Europe, where the share of gas in the power generation mix soared from just 6% in 1990 to 24% in 2012, with around 80% of incremental power generation from the year 2000 coming from natural gas. At the same time, roughly one-quarter of European gas demand is in the residential sector, where home heating is accounted for, making security of gas supplies of particular importance in winter months. Second, the natural gas market is becoming more global, thanks to the development of longer pipelines and, more significantly, inter-regional trade of LNG. Between 2012 and 2018, the volume of gas supply traded between regions is expected to grow by 30%. These growing inter-linkages mean that the impact of gas supply disruptions will no longer be limited to one or two countries, but could have a global impact.

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Box 3.1 Expanding IEA work on energy security

At their October 2009 meeting, ministers from IEA countries tasked the IEA with extending its monitoring and emergency response capabilities for oil to other forms of energy, particularly to natural gas. Ministers agreed that "the IEA can play a strong role in helping member countries improve their preparedness for possible gas supply disruptions, and co-ordinate their actions in case of an emergency, when appropriate".

More specifically, with respect to emergency response capabilities for natural gas, ministers agreed to endorse a role for the IEA to monitor progress in the gas markets and gas security policies of its member countries. They called on the IEA to provide advice and expertise to governments in the field of gas policy and to assist in their respective development and implementation of a gas strategy and plans in order to enhance long-term security of supply as well as emergency preparedness, including by conducting exercises and reviews.

Note: unless otherwise indicated, all tables, figures and boxes in this chapter derive from IEA data and analysis.

Trends in natural gas supply and demand

Natural gas demand in non-OECD economies overtook that of the OECD member countries in 2008; in 2012 OECD member countries accounted for 48% of global gas demand. The gap between non-OECD regions and OECD regions continues to widen, as gas demand shifts from mature OECD member countries to non-member economies where needs in the industrial and power sectors drive gas consumption upward. The picture within mature OECD regions varies markedly, as both OECD Americas and OECD Asia Oceania continue to see strong growth in gas demand, while European gas demand has been declining since 2010. A key factor of growth for all regions was the development of domestic production in many countries and the ability of importing countries to afford more expensive gas on global gas markets.

Global gas demand is expected to reach nearly 4 000 billion cubic metres (bcm) by 2018, largely driven by non-member economies, which will represent 76% of the incremental growth. China is still by far the fastest-growing region, with an average growth rate of 12% per year; this is more than twice the rate of the second-fastest growing region, Africa. The Middle East, Asia and Latin America are also characterised by relatively high growth rates, but incremental consumption remains largely dependent on domestic supply and the countries' ability to import external gas supplies. Among the OECD member countries, OECD Americas is the main driver, representing 66% of the OECD's growth, and is the second-fastest growing region based on absolute numbers. In stark contrast, OECD Europe gas demand is expected to rise only slightly from its current level.

Global gas production grew 2.1% in 2012, a smaller increase from the previous year (2.7%) when production grew faster than demand and resulted in significant storage build-ups. With the exception of 2009, this was the first time since 2001 that the annual gains of OECD regions were at parity with those of non-OECD regions. The two regions mostly responsible for the largest production gains were OECD Americas and the Middle East. In contrast, Asian and Former Soviet Union (FSU) gas production dropped slightly.

The main contributors to incremental gas supply over the period 2012-18 will be the United States, Australia and the FSU region. Together they will represent 38% of

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Table 3.1 Natural gas supply and demand, 1985-2018 (billion cubic metres)

	1985	1990	1995	2000	2005	2010	2012	2018*
OECD DEMAND								
Americas	579	625	721	794	770	850	893	977
Europe	288	323	388	475	543	567	513	525
Asia Oceania	58	84	104	131	153	198	229	261
Total OECD	926	1 032	1 213	1 400	1 466	1 615	1 635	1 763
NON-OECD DEMAND								
FSU/non-OECD Europe	614	762	611	597	653	681	677	709
China	13	16	18	28	49	109	149	295
Other non-OECD Asia	38	67	109	152	220	283	286	360
Latin America	46	58	70	94	122	152	160	190
Middle East	55	88	134	179	262	370	407	492
Africa	24	35	44	55	87	105	113	154
Total non-OECD	789	1 025	986	1 105	1 394	1 700	1 792	2 200
Total demand	**1 715**	**2 057**	**2 199**	**2 505**	**2 860**	**3 315**	**3 427**	**3 962**
OECD SUPPLY								
Americas	583	643	716	760	738	816	885	994
Europe	217	211	258	303	314	300	277	253
Asia Oceania	19	28	36	42	45	60	66	159
Total OECD	819	881	1 010	1 105	1 097	1 176	1 228	1 406
NON-OECD SUPPLY								
FSU/non-OECD Europe	683	831	721	725	812	842	865	954
China	13	15	18	27	49	95	109	173
Other non-OECD Asia	75	115	163	216	275	326	315	367
Latin America	46	60	72	103	145	163	173	200
Middle East	58	92	141	202	309	462	537	607
Africa	45	64	79	119	180	209	206	252
Total Non-OECD	920	1 178	1 194	1 392	1 771	2 097	2 205	2 553
Total supply	**1 739**	**2 059**	**2 203**	**2 498**	**2 868**	**3 274**	**3 433**	**3 959**

Note: Totals in table might not add up due to rounding.
* 2018 data are forecasts.
Source: IEA, 2013a.

additional gas supplies. This is a substantial break away from the trend observed in the previous decade when non-OECD regions represented 90% of additional supply.

Global gas trade is anticipated to expand by 30% from 2012 levels over the medium term, reaching almost 700 bcm by 2018. Global LNG trade is expected to grow slightly faster than pipeline trade and gain 31%, thanks to rapidly expanding LNG liquefaction and import capacity built in new markets.

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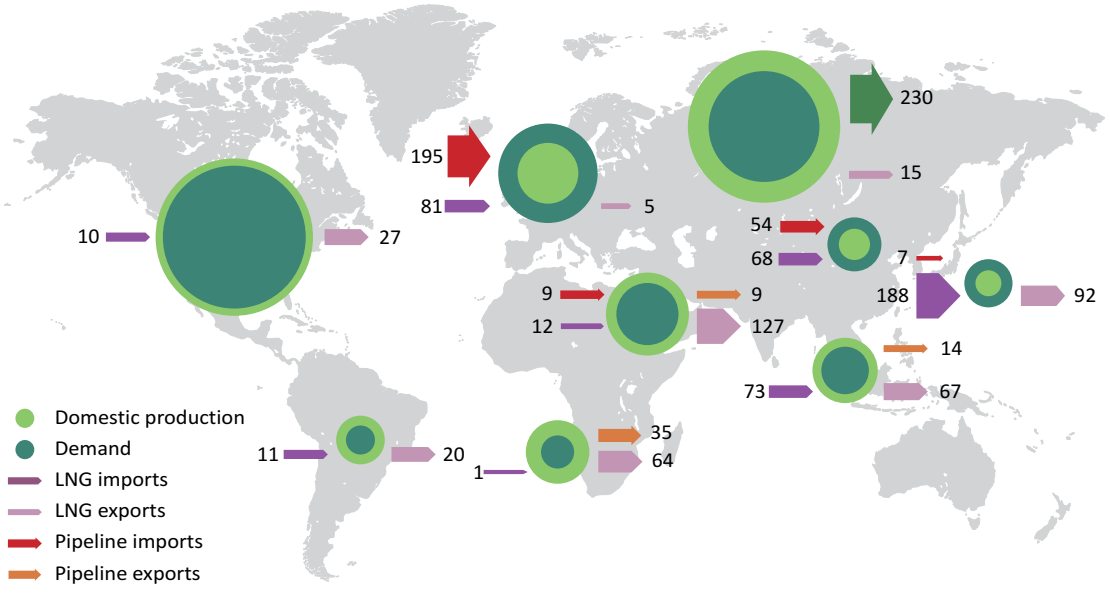
Figure 3.1 Inter-regional natural gas trade 2018 (bcm)



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: IEA,2013a.

Substantial developments in inter-regional gas trade are expected to take place in the period to 2018, including the emergence of North America as a net exporter in 2017. Europe is and will likely remain the largest importing region over the medium term, and with around 70% of its imports based on pipeline transport, is the world's largest pipeline importer. Chinese imports are expected to exceed those of OECD Asia Oceania by 2018, making China the second-largest net importer as the gap between demand and production widens to 122 bcm, three times the amount in 2012. OECD Asia Oceania is set to remain the world's largest LNG-importing region, supported by Japan – the world's largest LNG importer for the next decade – even though its share in the global LNG market is expected to gradually decline.

The relationship between gas and electricity generation

The steady increase in gas-fired electricity generation in the OECD countries has strengthened linkages between the power and gas sectors. At the company level, there has been a convergence between gas and electricity, with power companies investing in gas assets and gas companies building gas-fired plants. In Europe, there are few solely gas or power companies any longer. In Japan, the six big power utility companies have their own long-term LNG contracts, while, gas companies have also edged into the electricity market.

Natural gas has been the fuel of choice for investors in new generation energy for almost two decades in many OECD countries for many reasons: gas-fired power plants can be built quickly; upfront costs are relatively low; emissions are about half those of coal-fired plants; and there is generally a lower risk of public opposition compared to investments in coal-fired and nuclear power plants. Plants can also be added in smaller increments, an important factor when demand recovery is uncertain.

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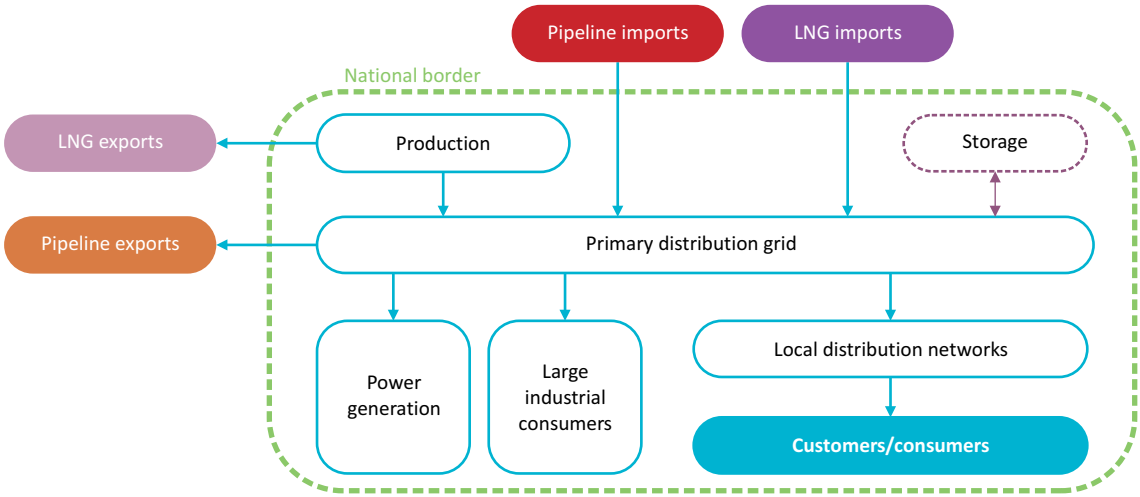
Stronger interdependence of the two sectors has implications for the security of supply. In countries and regions experiencing simultaneous gas and electricity demand peaks, such as most parts of northern Europe, the demand patterns of the power supply industry can compound rather than reduce the amplitude of peaks in gas demand. The occurrence of simultaneous peaks may create additional stress on both power and gas systems, increasing the supply risks for both. Of course, a flexible power sector may be able to play an important role in alleviating any gas supply problems that may arise through fuel switching, either in dual gas-fired plants or by switching to other power generation sources such as coal. Given the important role that flexible gas plants can play in addressing variability in renewable electricity production and the growing interdependency of power and gas markets, policy frameworks to ensure security of electricity supply should assess issues relating to gas supply and the potential impact of gas supply disruptions on electricity delivery systems.

Figure 3.2 Natural gas supply chain



How emergency response for oil and gas differ

While experience and lessons from emergency response policies for oil can be a useful point of reference for the case of natural gas, appropriate emergency response measures can differ substantially due to the unique nature of gas. Natural gas is capacity-bound to a highly capital-intensive transportation and distribution infrastructure, and there is little demand-side response in some large consumer sectors, for example in the household and space heating sector.

Natural gas is far less fungible than oil, particularly with regard to transporting the fuel to end users. For example, downstream gas transport is always performed by fixed infrastructure (i.e. pipelines). While there are also many downstream oil distribution pipelines in use, a large-scale disruption to one pipeline can be isolated, and tanker trucks can be used to distribute the oil instead. Repairs to oil pipelines are also less costly than repairs to gas pipelines because of the elevated pressure of the gas system. Gas is rarely transported to consumers in trucks, which means that the distribution system is less resilient. Where oil tanker trucks are used instead of pipelines the loss of a tanker truck will hardly affect the distribution of oil. If any part of a major gas transmission

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pipeline is destroyed, supply downstream is typically stopped until the damage can be repaired or the pipeline replaced; alternative arrangements by road are not an option.

Furthermore, gas transport is more difficult to scale up than oil transport. Indeed, the available spare capacity, either physically or contractually, is sometimes limited in existing gas pipelines. By contrast, in the case of extreme oil demand, more oil trucks can deliver more oil to petrol stations via the road system, and there are generally empty tanker trucks available at any one time in any one region; such immediate overland transport solutions are unheard of for natural gas.

Box 3.2 Natural gas disruptions in the past

A number of gas supply disruptions have occurred over the last decade, arising from weather-related catastrophes (e.g. hurricanes), accidents (e.g. fires, explosions) and contractual disputes.

Recent significant gas crises occurred in the United States (2005 and 2008), the United Kingdom, Italy and Ukraine (2006); Turkey, Greece and Australia (2008). At the beginning of 2009, Europe suffered its worst gas supply disruption to date, with Russian supplies transiting Ukraine interrupted for almost three weeks; in total some 7 billion cubic metres (bcm) of supply was lost, including 2 bcm of supply for Ukraine. Coming at a time of very high demand because of cold weather, this crisis had a far greater impact than even the hurricane-induced shortages in the United States in 2005 and 2008. Some Eastern European countries with heavy reliance on Russian gas and only limited storage capabilities were especially badly affected, with major industrial closures and real hardship in the domestic sector.

Possible emergency response measures for natural gas

Natural gas emergency response policies are designed to cope, temporarily, with extraordinary events impacting normal market functioning. It is important to note that sharp or sustained increases in gas demand can produce similar effects to those produced by a sudden reduction in supplies. Such increases in demand are not only driven by extreme cold weather – which leads to a rise in gas demand for space heating (either directly, when gas is used in residential heating, or indirectly, from additional gas-fired power generation) – but also extreme hot weather leading to a rapid rise in gas-fired power demand to run air conditioners.

To some extent, such seasonal fluctuations can be predicted and should not be classified as gas crises. Well-designed markets can ensure that market participants are well placed to deal with such situations. Emergency gas measures should only be considered as a protection of last resort, after the market has proven itself unable to withstand the impact of a gas supply disruption.

The following section briefly outlines a portfolio of measures that could reasonably be taken in the event of a crisis in the gas market. Issues related to emergency stockholding, analogous to those in place in the oil market, are examined before considering other possible actions for mitigating gas crises.

Emergency gas stocks

Gas stocks are a central part of the gas industry's structure, responding to normal but often large seasonal and even daily demand fluctuations. Emergency gas stocks are

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defined as physical stockpiles of natural gas which are not available to the market under normal conditions. As in the case of oil, emergency gas stocks can be either government-owned volumes or consist of stocks held by industry, based on a government-imposed stockholding obligation. In either case, the stocks are held with the aim of protecting consumers against non-market risks. A non-market risk may be understood as a risk that cannot be expected to be covered by the market under normal conditions, and thus falls outside the reliability standards of a particular market.

Different options exist for the storage of gas, depending on a given country's geological structure, budget and security and commercial requirements. Gas storage can be underground (in depleted oil or gas reservoirs, aquifers or salt cavern formations) or aboveground (in liquid form, as LNG). The rate at which gas can be put into or taken out of storage (injection/withdrawal rates) varies substantially from one storage type to another. It is likely that a mix of fast and slow withdrawal gas storage would be needed in order to enable a complete emergency gas storage capability with a range of withdrawal rates.

Geological, or technical, barriers are perhaps the greatest impediment to developing sizeable gas storage facilities throughout the IEA countries. Natural gas, like any other gas, needs to be fully contained at all times to prevent it mixing with the air and/or escaping. As well as needing confinement, natural gas has a lower energy density than oil which means that, at standard temperature and pressure, a volume of gas contains much less energy than the same volume of oil. If storage is to be economical, the energy density of gas needs to be increased – gas must therefore be stored either at very high pressures or at low enough temperatures (-160°C) so that it forms a liquid.

The operating costs for storing gas either under high pressure or in a liquefied form are well beyond those for oil storage. High pressure environments require specialist materials such as thick steel pipelines and powerful compressors. Storing natural

Box 3.3 Costs of emergency gas stocks

Conceptually, gas stocks are often viewed as the equivalent of "emergency oil stocks"; in fact, gas and gas storage differs markedly from oil. A fundamental difference is cost. Initial capital costs of building gas storage facilities can range from between five to seven times the costs of underground oil storage facilities per tonne of oil equivalent (toe) stored. The capital cost of LNG storage facilities can be up to ten times the cost of stocks in oil tanks or approximately 50 times the cost of underground oil storage per toe stored.

Furthermore, the volume of gas that is required to be maintained in a gas storage site emptied of useful working gas – referred to as the "cushion gas" – can vary significantly according to the type of storage. Whereas cushion gas can be limited to around 25% of total gas in the case of most salt caverns, it approaches 50% for depleted fields, and can reach up to 80% for aquifers. In certain cases, depending on the market price for gas, cushion gas can account for up to half the cost of the investment.

Variable costs for maintaining gas in storage are also significant. Variable costs for gas storage are determined by various economic factors such as interest rates, cost of maintenance and cost of personnel, but also include another factor specific to gas storage – gas leakage. The variable cost of maintaining enough gas in emergency storage to satisfy a 90-day net import standard across the IEA countries is estimated at between 10% and 20% of the capital cost of the facilities per year.

Assuming suitable sites within the IEA countries could be found, the cost of developing gas storage in depleted fields is estimated at up to EUR 1.00 per cubic metre of working gas. The cost of developing salt cavern storage is higher, approximately twice the cost per cubic metre of working gas.

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gas under high pressures will typically only be pursued if there is suitable geology for underground storage, such as in depleted oil fields.

When using depleted fields for gas storage, the pressure of the field must be maintained at all times, otherwise the geological structure could be altered. This means that even when the field is technically empty of working gas it must have sufficient gas in store to maintain sufficient pressure to maintain the geological structure. The volume of gas left in a gas storage site emptied of useful working gas is referred to as the "cushion gas". The volume of cushion gas required to develop a large underground storage facility can account for up to half the cost of the investment.

Alternatives to emergency gas stocks: other possible emergency measures

In the absence of emergency gas storage, or in combination with the release of gas stocks, other tools can be designed to alleviate disruptions in gas supply. Governments may use some of the tools discussed below to reduce the economic or social impacts of an unforeseen disruption in supplies or a surge in demand for gas.

Supply response

Gas markets with access to spare import capacity from LNG terminals or unused pipeline or interconnector capacity might be able to benefit from some type of supply response to a gas emergency if contractual circumstances permit.

In the pipeline market, this response would rely on there being unused pipeline capacity with associated production flexibility. Some of this import capacity can be used by the capacity owner to increase purchases from upstream suppliers, if supply is available and contractual conditions allow. Alternatively, the capacity could be made available to the market by the system operator if the capacity holder is unable, or unwilling, to secure additional gas supplies.

In the LNG market, a supply response would rely on the market's ability to purchase additional LNG tanker cargoes. There are two sources of available LNG cargoes; the "spot" LNG market and LNG cargoes diverted from their original destination by agreement of stakeholders. As the LNG spot market expands, a flexible supply response is possible in each regional IEA market. With spare LNG receiving capacity, regions could buy gas from the uncommitted "spot" LNG market. However, this market is global; increased buying by one region reduces supply in the other two and puts global pressure on prices.

When LNG production trains run at less than 100% capacity, it may be possible, within the framework of existing long-term LNG contracts, for customers to request that suppliers increase production. LNG cargoes can also be released from fulfilling their normal obligations under long-term contracts and diverted to alternative destinations, if both buyers and sellers agree. This would, in effect, swap cargoes from the long-term contract market into the global "spot" market, but would only be a net gain in supply if the buyer could also decrease domestic demand or draw down gas from storage. A combination of reduction in demand in unaffected regions and increased production and cargo diversion could constitute a global LNG response to a supply emergency.

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Demand response

Demand response occurs when customers decide to modify their consumption depending on the price of gas in a market. In some cases, there is often a time lag in wholesale price changes filtering through to certain classes of consumer, for instance those in the residential sector. This time lag might justify government action to make domestic gas consumers aware of a supply disruption. Short-term gas-saving measures might be required to reduce demand over relatively short periods. Given the increasing use of gas in power generation, similar measures could be used to stimulate demand-side reactions in the electricity sector.

One way of allocating natural gas when supply is disrupted is to ration its use through demand restraint, whereby natural gas consumption is restricted. Such a policy goes beyond the voluntary limitation that occurs when customers decide to modify their consumption depending on the price of gas in the market. Governments could impose strict limitations on gas consumption in specific sectors (e.g. industry) in order to assure supplies to predetermined priority customers (e.g. households or vital services such as hospitals). In liberalised markets this is normally an explicit provision in the network code governing the physical operation of the gas system.

Interruptible contracts

Interruptible customers are industrial customers who consume large volumes of gas per year and agree to have their gas supply interrupted for a maximum number of days in a year in order to obtain a reduction in gas price. On average, customers with these contracts agree to a maximum of 10 to 20 days of zero supply (if necessary) in a year. Generally, large gas consumers on interruptible contracts receive volume-related discounts on wholesale gas costs, in addition to a reduction in transportation costs designed to offset the potential loss of supply.

While interruptible customers are certain to have their gas supplies cut in a supply disruption, the volume saved is unlikely to be sufficient to completely mitigate a large-scale disruption. Nonetheless, this option can be useful as part of a suite of tools for dealing with such interruptions.

Fuel switching

Gas customers who can rapidly switch to an alternative fuel offer a very useful type of demand response for managing a gas emergency situation. In most cases the choice of alternative fuel is technically limited to oil or oil products, as oil can be injected into gas turbines or sprayed into boilers.

While there is a penalty in terms of efficiency and increased maintenance, some gas-fired power stations in Europe and North America can often switch to light oil (gasoil) and some in Korea and Japan can often burn crude oil if necessary. In order for these plants to switch fuel several conditions must be met, including adequate stores of oil available at the site. Governments can set specific obligations to maintain minimum stock levels of alternative fuels for use in a gas crisis. Of course, the power sector and district heating plants can, and do, switch between fuels and power plants regularly in some countries as part of normal (or even abnormal) market functioning. This highlights the importance of having a diverse range of energy sources[1] for power generation, to provide maximum flexibility in the event of a natural gas emergency.

1. Including renewables, nuclear and coal in addition to natural gas, oil and petroleum products.

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Overview of gas security of IEA countries

IEA countries show a marked diversity in their demand, supply and market conditions with respect to natural gas. The three major OECD regions provide stark contrasts, from the isolated and LNG-dependent markets of OECD Asia Oceania, to the strongly interconnected, pipeline-based markets of North America, to the varied markets of Europe. These factors will determine how countries perceive the risks associated with a gas disruption and the appropriate emergency response measures required to mitigate such events.

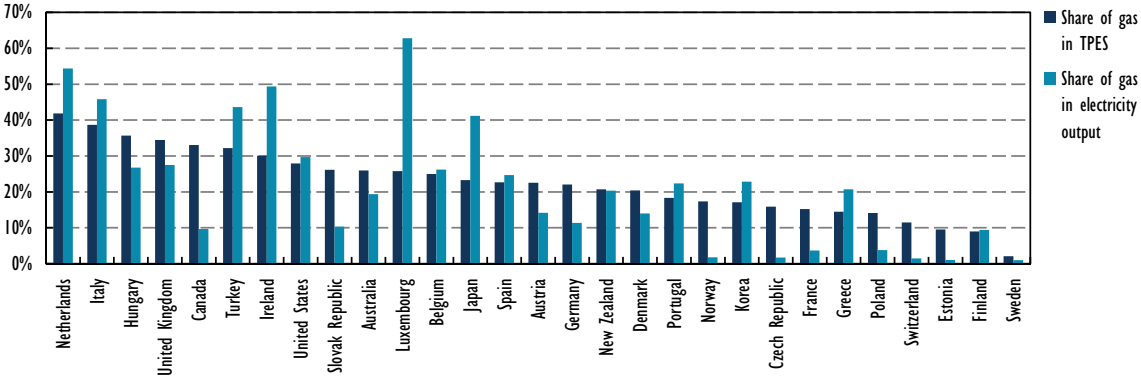
The section below provides an overview of the role of natural gas in IEA countries and of the emergency measures they have in place for responding in a gas crisis.

The role of natural gas in IEA countries

The role of natural gas in the primary energy supply mix of IEA countries varies substantially, ranging in share of TPES from over 40% in the Netherlands to 2% in Sweden. However gas makes up a substantial share of the supply mix for the vast majority of IEA countries, accounting for over 10% of TPES in 26 of its 29 members; gas exceeds 30% of TPES in seven IEA countries.

In many IEA countries, the power sector is particularly dependent on natural gas. The share of gas in electricity output is in excess of 20% in 15 countries, and over 40% in 6 countries.

Figure 3.3 Natural gas in IEA countries: 2012



Source: IEA, 2013b.

Peak demand exceeds average demand by more than 50% in 24 of 29 IEA countries, and exceeds average demand by a factor of as much as 100% for more than half of IEA countries. This can be due to seasonal factors where heating is the main end use; in France, for example, January demand can be four times August demand. This volatility of demand can be exacerbated by the increasing role of gas in power generation – especially where such power meets peak demand, fills gaps when other plants are unexpectedly unavailable, and/or is increasingly used as backup for variable renewables – resulting in quite sharp demand peaks for gas. Regions with these demand patterns require flexible arrangements to ensure secure supply, including differing types of storage (including storage with quicker drawdown rates to meet power sector needs), as well as the more traditional long-term supply contracts.

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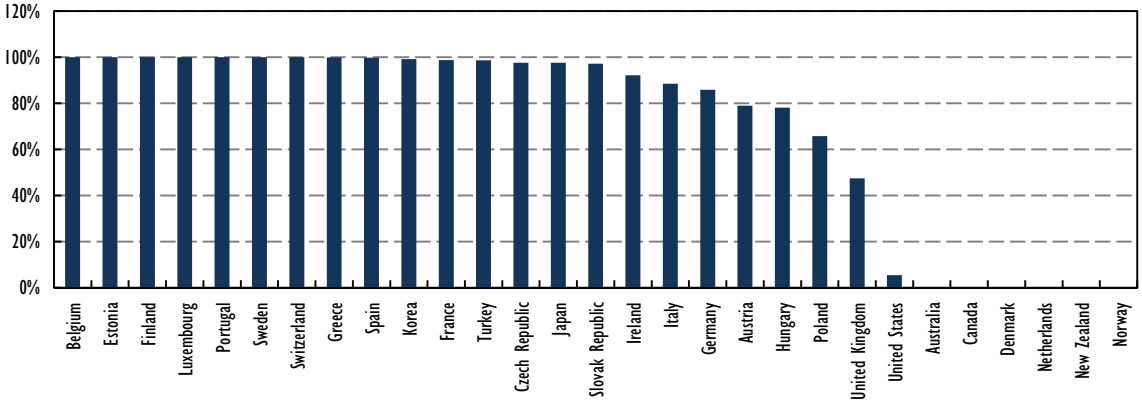
Import dependency

Most IEA member countries depend on imports to meet their domestic gas needs. Only six member countries are not dependent on imports; of the six, five are net exporters. At the other end of the spectrum, 16 IEA countries have an import dependence exceeding 90% with 9 of these countries being essentially 100% dependent on imports to meet domestic gas demand. Regionally, high levels of dependence on imported gas are mainly found in most of Europe and in Asia (Japan and Korea). Member countries in North America, Oceania and the European countries adjacent to the North Sea are relatively well-endowed in terms of gas resources and thus not exposed to the same inherent import risk.

Figure 3.4 Natural gas import dependence: 2012



Source: IEA, 2013c.

Most IEA countries benefit from relatively diversified sources of imported gas. This is particularly the case for LNG-importing countries in both Asia and Europe, where specific policies have been put in place in order to limit import reliance on any one country. The greatest exposure to a single supplier is in Eastern Europe, where countries from the Baltic to the Balkans show a common structural reliance on Russian pipeline gas imports.

Gas storage capacity

Gas storage is a valuable tool for responding to demand swings and supply disruptions, as demonstrated by the 2009 crisis. Commercial storage capacity has been developed in the vast majority of IEA countries as a means of addressing both seasonal variations in demand and situations of peak demand. In some instances, specific volumes of this capacity are used to hold gas stocks for emergency purposes. This is the case in several European IEA countries which impose some form of gas storage obligation, in some cases requiring the transmission system operator (TSO) to book a share of the country's commercial storage capacity to meet its security standards. In Hungary, a dedicated stockholding agency holds just under 1 bcm of gas as government-controlled emergency storage. These storage measures provide a powerful tool for correcting acute, short-term market shortages.

Underground storage remains the most common means of holding gas stocks; however the potential to develop underground storage capacity varies according to each country's geology. Some countries have resorted to developing LNG storage as an alternative, although this is more limited in size due to higher related costs.

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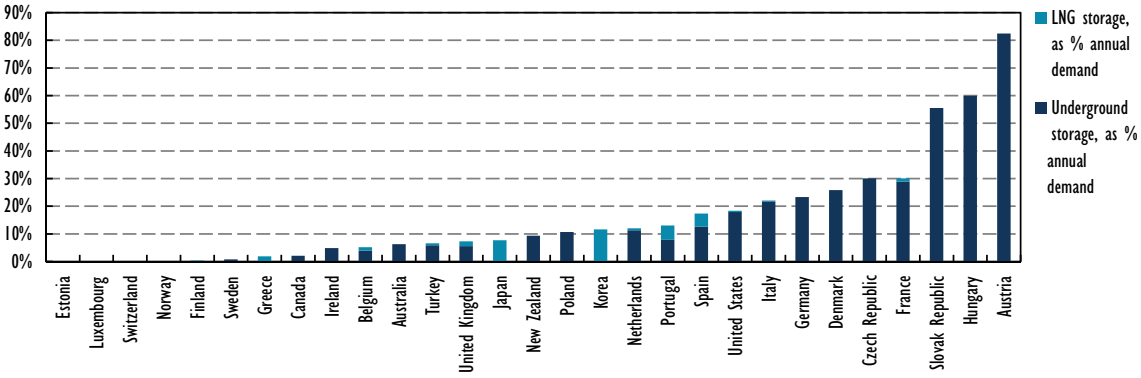
Four IEA countries have no gas storage facilities at present. Estonia uses neighbouring underground storage facilities in Latvia, while Luxembourg is well connected to storage facilities in neighbouring countries through four interconnecting points. Similarly, Switzerland uses underground storage in France to balance the Swiss gas network. Norway, which is a large net exporter of gas with only small volumes of domestic consumption, has not developed any significant storage capacity.

The number of LNG regasification terminals has grown significantly within IEA countries in recent years, providing both a source of stable, flexible and diversified gas supply, and a place of short-term storage at the terminal site. Practically all storage capacity in Japan, Korea and Greece is held at LNG regasification sites; both Japan and Korea have built a large number of LNG terminals across the countries, thus forming a highly resilient basis for their gas supplies. LNG storage also accounts for a large share of national storage capacity in Belgium (25%), Portugal (40%) and Spain (27%). The United States has built numerous LNG terminals, but at present most are significantly under-utilised because of the substantial level of domestic gas production. The low level of import dependence in the United States means that domestic storage already provides a very high level of resilience.

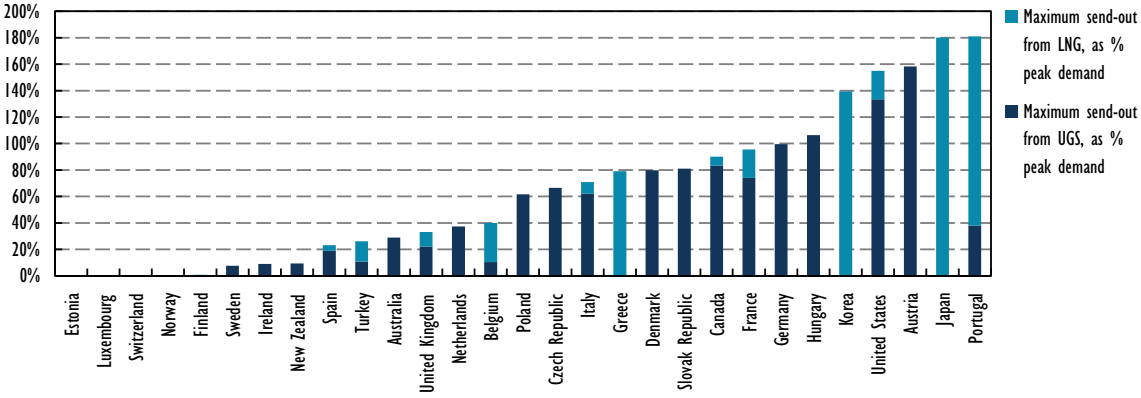
Taking both underground and LNG storage capacities together, 14 member countries have storage capacity that can meet at least 10% of annual demand; storage capacity surpasses 20% of annual demand for eight countries. Only three countries have gas

Figure 3.5 Storage capacities as a percentage of annual demand



Sources: IEA, 2013c.

Figure 3.6 Storage send-out capacities as a share of peak demand



Sources: IEA, 2013c.

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storage capacity that surpasses 50% of annual demand. In Hungary, this has been achieved through government-designed public stockbuilding; Austria's high gas storage levels are commercially-developed depleted production fields.

Assuming storage capacities are filled to their maximum levels (as is usually the case at the beginning of winter), and that the volumes can be dispatched to demand centres, 12 IEA countries could meet 80% or more of their peak demand by means of a theoretical maximum drawdown on their storage. Six countries could theoretically cover all their peak demand in this way.

External infrastructure resilience

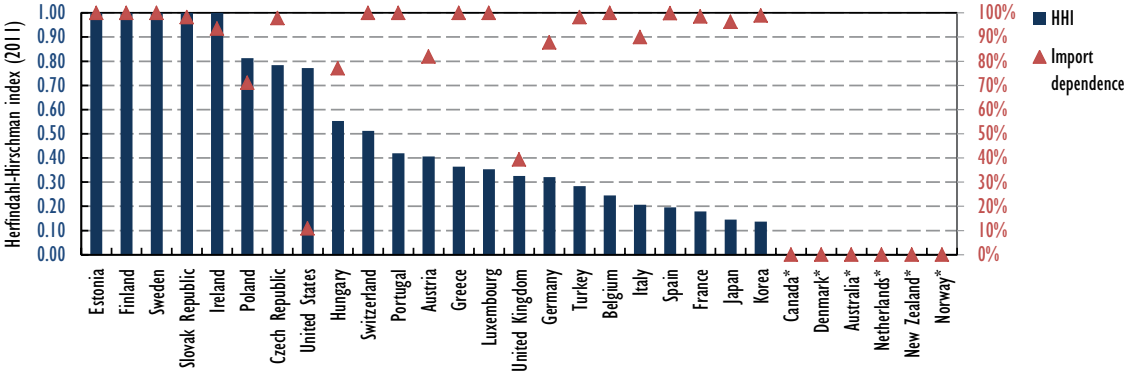
Developing domestic storage capacity is not the only way to enhance gas security: establishing interconnections with neighbouring countries is another key means of improving a country's resilience. Indeed, it is worth noting that some countries (e.g. Czech Republic, Luxembourg, Slovak Republic, Sweden and Switzerland) are connected to storage sites located in neighbouring countries.

Eight IEA countries have a maximum inflow pipeline capacity that exceeds their peak demand, thus providing a large degree of security of supply; maximum inflow capacity could theoretically cover more than 70% of peak demand in 11 IEA countries. It should be noted, however, that the pipeline infrastructure in most of these countries is well-developed because it often serves as a transit route. As such, although the capacities are high, the total volume of gas transiting through these inflow points cannot be considered to be accessible to the countries themselves.

Not all IEA countries are reliant on pipeline supplies, however, and LNG supplies are of vital importance to otherwise isolated gas markets such as Japan and Korea. LNG supplies have also played an important role in strengthening the resilience of the gas markets of Western Europe. Five countries (Greece, Japan, Korea, Portugal and Spain) theoretically could cover their peak demand with their LNG import capacity alone.

Diversification of entry points and supplies is a key measure of external resilience, although the ability of a country to diversify its supply sources depends significantly on

Figure 3.7 Import diversity of supplies



* Not applicable - net exporter or no imports.
Note: The Herfindahl-Hirschman Index, an economic concept widely applied in anti-trust and competition law, is defined in this context as the sum of the squares of the market shares of the countries of imports for any given country. The index ranges from 0 (high diversity of supply) to 1.0 (one monopolistic supplier). It is worth noting that the index does not take into account the level of import dependence. (Therefore marginal net importers, if they only import from one source will appear with an index of 1.)

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its inherent geography. The external resilience of certain Central and Eastern European countries is inherently weak, with many depending on just one dominant entry point and supplier (namely, Russia). This is also the case in Finland (depending on Russia) and Sweden (depending on Denmark), both of which are 100% dependent on a single entry point and supplier. Many European countries are currently investing in making key gas pipelines reversible so as to provide additional resilience in the event of a crisis.

Policies and emergency measures

The majority of IEA countries have taken specific steps to develop natural gas emergency policies, including establishing a gas-specific national emergency strategy organisation (NESO) or dedicated emergency organisation structure for dealing with gas disruptions. Countries that have not designed any such policies or do not have a NESO structure are for the most part either gas exporters and/or have highly resilient systems with numerous entry points (e.g. North America and Japan and Korea).

Box 3.4 European Union regulation on gas security

Following the Russia-Ukraine gas dispute in January 2009, the European Union sought to establish common standards for security of gas supply for the whole European Union. To this end, the European Parliament adopted a regulation to safeguard security of gas supply, which entered into force on 2 December 2010.

According to the regulation, EU member states must designate a particular regulatory or government authority with specific responsibility for gas supply security. This designated authority is responsible for monitoring gas supply developments, assessing risks to supplies, establishing preventive action plans and setting up emergency plans. EU member states are also committed to collaborating closely in a crisis, including through a Gas Coordination Group and through shared access to reliable data and information regarding supply.

The regulation establishes a common indicator for gas security, known as N-1. This refers to a situation where the most significant element of a country's gas network is out of operation, such as an import pipeline or production facility. The N-1 standard is used to define the country's supply standard, which ensures that vulnerable customers, particularly households, continue to receive gas supplies even under exceptionally difficult supply circumstances.

EU member states are required to carry out an assessment of security of gas supply based on a number of common elements set out in the regulation. These include assessments of the N-1 and supply standards, a description of the market, stress tests and interaction with other member states. On the basis of the risk assessment, each country then prepares preventive action plans and emergency plans which must be updated every two years.

Source: European Parliament (2010), "Report on the proposal for a regulation of the European Parliament and of the Council concerning measures to safeguard security of gas supply and repealing Directive 2004/67/EC", 29 March 2010, www.europarl.europa.eu/sides/getDoc.do?type=REPORT&reference=A7-2010-0112&language=EN.

Nine IEA countries have specific policies designed around implementing interruptible contracts, or have based the resilience of their systems partly on flexible interruptible contracts. Six IEA countries have developed fuel-switching policies. It should be noted that the percentage of gas-fired plants that can switch fuels has decreased over the last decade, reflecting the progressive roll out of combined cycle gas turbine (CCGT) plants. Indeed, the greater efficiency of these plants means that they are less flexible and thus less able to switch fuels easily.

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A number of IEA countries (all of which are in Europe) have placed some form of stockholding obligation on their gas industry. Seven countries have placed a gas stock obligation on their domestic players, and eight countries have imposed an obligation on certain gas-consuming industry players to hold stocks of an alternative fuel (e.g. gasoil, for gas-fired power plants) to be used in the event of a gas disruption. Combined with the public stocks that Hungary has at its disposal, half of the member countries of the IEA have developed specific stockholding measures related to gas that would provide strong resilience in the event of a disruption.

Table 3.2 Overview of gas emergency policies in IEA member countries

	NESO for gas disruption	Able to cope in an N-1 situation	Policy promoting interruptible contracts	Policy promoting fuel switching	Government/ agency stockholding	Gas stock obligation	Alternative fuel obligation
Australia	yes	yes					
Austria	yes	yes					
Belgium		yes					
Canada		yes					
Czech Republic	yes	yes					
Denmark	yes	yes				yes	
Estonia	yes						yes
Finland	yes	yes					yes
France	yes	yes					
Germany	yes	yes					
Greece	yes	yes	yes	yes			yes
Hungary	yes	yes		yes	yes		
Ireland	yes		yes	yes			yes
Italy	yes	yes	yes	yes		yes	
Japan		yes					
Republic of Korea		yes					
Luxembourg	yes						
Netherlands		yes					
New Zealand	yes	yes	yes	yes			
Norway		yes					
Poland	yes	yes	yes			yes	
Portugal	yes	yes				yes	yes
Slovak Republic	yes	yes				yes	
Spain	yes	yes	yes			yes	
Sweden	yes						
Switzerland	yes	yes		yes			yes
Turkey	yes	*	yes	yes		yes	yes
United Kingdom	yes	yes	yes				yes
United States		yes					
	22	24	8	7	1	7	8

* Information unavailable

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Concluding remarks

As in the case of oil, each country determines which natural gas emergency response measures are most appropriate, depending on its domestic market conditions and policy preferences. Chapter 4 describes in further detail the gas markets and emergency response policies of individual member countries.

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International Energy Agency (IEA) (2013a), *Medium-Term Gas Market Report*, OECD/IEA, Paris.

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IEA (2013c), *Natural Gas Information,* OECD/IEA, Paris.

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Emergency response systems of individual IEA countries

The ability of the International Energy Agency (IEA) to co-ordinate a swift and effective international response to an oil supply disruption stems from the strategic efforts of member countries to maintain a state of preparedness at the national level. Energy security is more than just oil, as the role of natural gas continues to increase in the energy balances of IEA countries. The most recently completed cycle of Emergency Response Reviews (ERRs) reflected this change by assessing, for the first time, the member countries' exposure to gas disruptions and their ability to respond to such crises. This chapter provides general profiles of the oil and natural gas infrastructure and emergency response mechanisms for 29 IEA member countries.

Each country profile is set out in the following sequence:

Key data

Key oil data, 1990-2018
Key natural gas data, 1990-2018
Total primary energy source (TPES) trend, 1973-2012
Infrastructure map

Country overview

OIL
Market features and key issues
Domestic oil production
Oil demand
Imports/exports and import dependency
Oil company operations
Oil supply infrastructure
Refining
Ports and pipelines
Storage capacity
Decision-making structure
Stocks
Stockholding structure
Crude or products
Location and availability
Monitoring and non-compliance
Stock drawdown and timeframe
Financing and fees
Other measures
Demand restraint
Fuel switching
Other

GAS
Market features and key issues
Gas production and reserves
Gas demand
Gas import dependency
Gas company operations
Gas supply infrastructure
Ports and pipelines
Storage
Emergency policy
Emergency response measures

Disclaimer: This chapter on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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Australia

Key data

Table 4.1.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	643.0	802.4	545.3	561.5	490.4	480.0	553.4
Demand (kb/d)	737.9	872.4	1 027.6	1 059.7	1 104.6	1 126.1	1 094.6
Motor gasoline	297.9	308.0	327.9	315.4	313.5	316.6	-
Gas/diesel oil	175.3	229.3	298.7	351.9	381.4	399.9	-
Residual fuel oil	41.7	36.6	36.4	28.9	30.2	27.4	-
Others	223.0	298.6	364.6	363.6	379.5	382.2	-
Net imports (kb/d)	94.9	70.0	482.3	498.2	614.2	646.1	541.2
Import dependency (%)	12.9	8.0	46.9	47.0	55.6	57.4	49
Refining capacity (kb/d)	675.0	812.4	755.0	761.8	761.8	761.8	-
Oil in TPES (%)**	36	32	32	32	34	33	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.1.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	20 475	32 819	35 840	48 370	51 244	53 850	140 577
Demand (mcm/y)	17 684	22 567	28 717	35 370	37 905	48 662	55 121
Transformation	4 893	5 184	6 915	11 353	13 128	0	-
Industry	7 180	8 730	9 819	9 715	9 788	0	-
Residential	2 259	2 983	3 290	3 652	3 756	0	-
Others	3 352	5 670	8 693	10 650	11 233	0	-
Net imports (mcm/y)	- 2 791	- 10 252	- 7 123	- 13 000	- 13 339	- 5 188	- 85 456
Import dependency (%)	- 15.8	- 45.4	- 24.8	- 36.8	- 35.2	- 10.7	- 155
Natural gas in TPES (%)	17	18	17	21	22	26	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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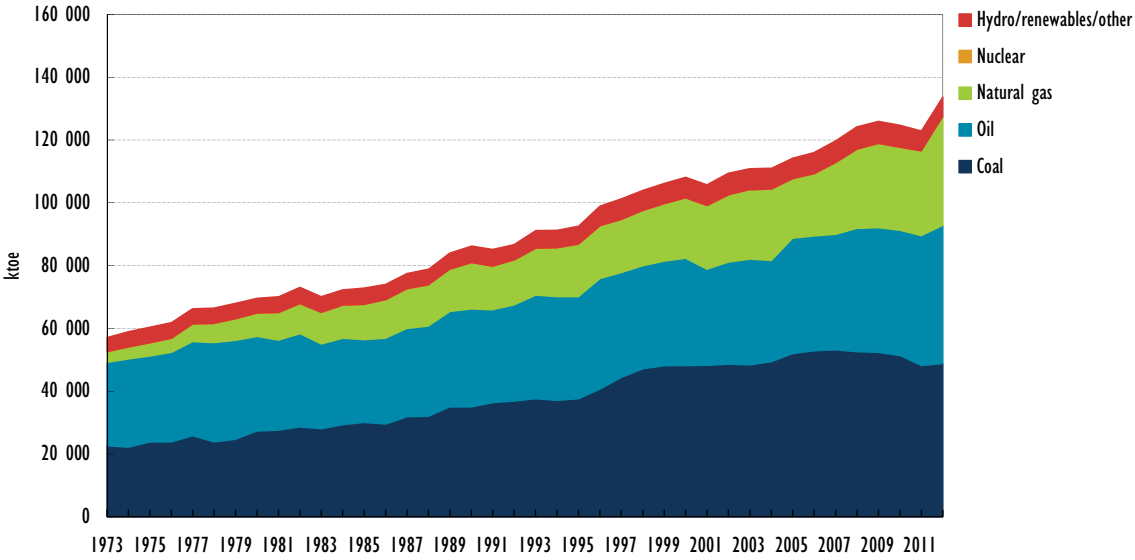
Figure 4.1.1 Total primary energy source (TPES) trend, 1973-2012



Note: unless otherwise indicated, all tables and figures in this chapter derive from IEA data and analysis.

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Map 4.1.1 Oil infrastructure of Australia

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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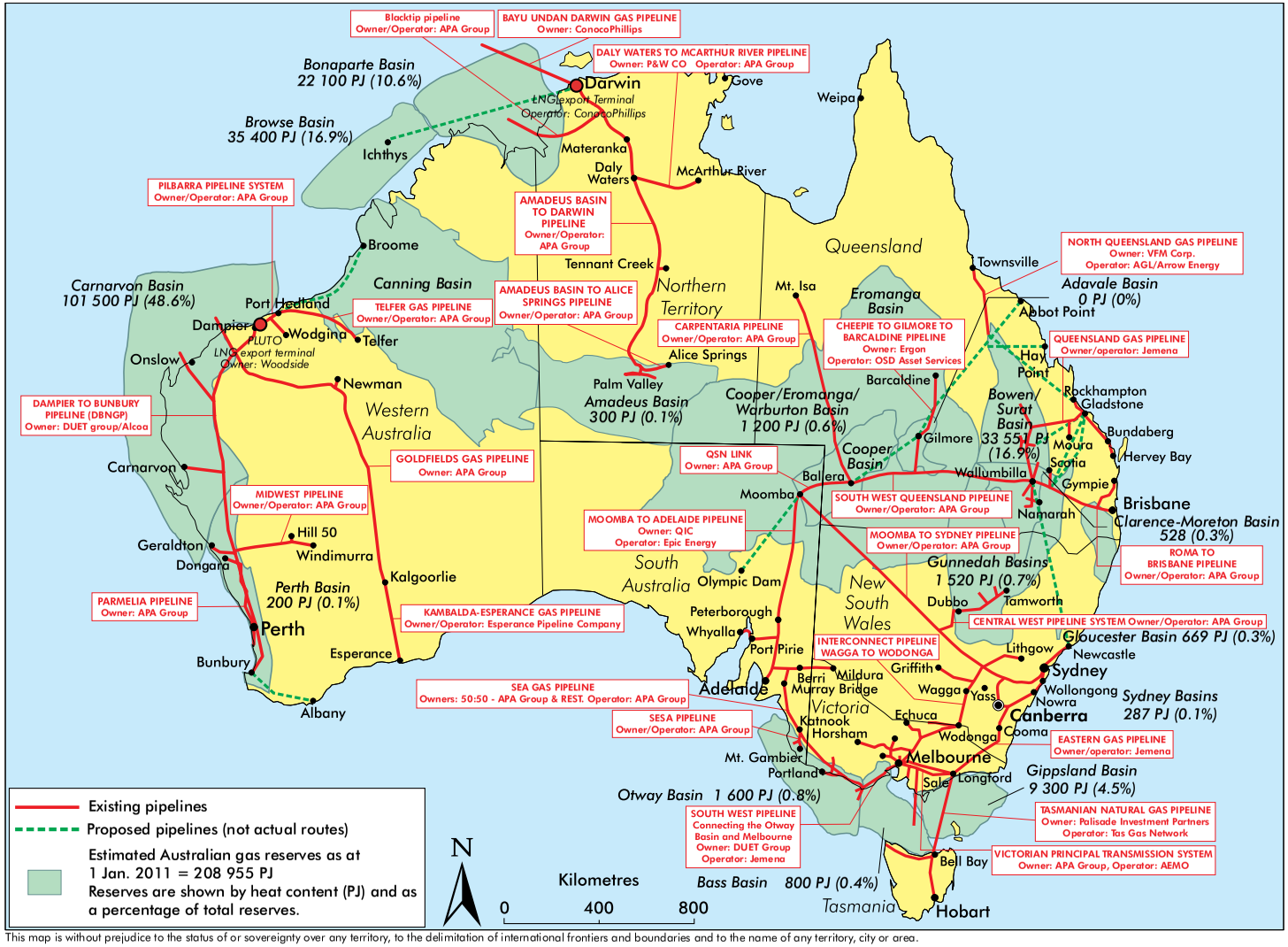
Map 4.1.2 Gas infrastructure of Australia



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Country overview

Together, oil and natural gas accounted for 59% of Australia's total primary energy supply (TPES) in 2012. In the case of natural gas, domestic production will more than satisfy the country's gas needs for the foreseeable future, and Australia's gas export capacity will continue to increase. However this is not the case for oil, where a growing share of future oil demand will be met by imports of refined products.

Australia does not impose minimum stockholding requirements on oil companies, nor does it have public stocks; all oil stocks in Australia are held by industry on a commercial basis. Until 2000, the year in which its domestic crude production peaked, Australia was either a relatively marginal oil importer or an occasional net oil exporter. As such, Australia's commercial stockholdings more than adequately met the requirement of the International Energy Agency (IEA). Since 2000, declining domestic oil production coupled with oil demand growth has resulted in a steady rise in net imports, and thus the amount of oil stocks necessary to meet Australia's IEA obligation.

Australian emergency policy relies on the domestic market to respond to supply shortfalls in the first instance, including consumer response to price signals. Australia's capacity for short-term surge production and fuel switching is limited. In a declared state of emergency, the Australian government has legislative powers to control the storage, transfer, sale and production of liquid fuels. Initial light-handed demand restraint measures and a rationing scheme at the wholesale level can quickly be escalated to invoke heavier-handed measures including retail rationing. Australia's state and territory governments have constitutional powers for planning and co-ordinating emergency response within their territorial boundaries. In the case of a major oil crisis affecting more than one jurisdiction, ministers have agreed that the National Oil Supplies Emergency Committee (NOSEC), which includes the fuel industry, will advise on appropriate actions.

The management of temporary gas shortfalls is primarily undertaken by gas market participants and jurisdictional governments, depending on the nature and size of the event. In the case of a major gas crisis affecting more than one jurisdiction, the National Gas Emergency Response Advisory Committee (NGERAC) will advise energy ministers across jurisdictions, who in turn are able to enact emergency powers within their corresponding jurisdictions. These powers can include issuing directions for production, transmission, distribution and allocation of natural gas.

Oil

Market features and key issues

Domestic oil production

The largest of the country's petroleum producing basins are the Carnarvon Basin in the northwest of Australia and the Gippsland Basin in the southeastern Bass Strait. Production of crude oil and condensate from the Carnarvon Basin, which accounted for around 77% of total production in 2010-11, is mostly exported. Production from the Gippsland Basin has declined steadily since its peak in the mid-1980s and accounted forunder 15% of total production of crude oil and condensate in 2010-11. Production from this basin is predominantly used in domestic refining.

Most of Australia's crude oils are of a high quality, light-sweet grade, as represented by its main crude streams (Gippsland, Bayu-Undan and Cossack). These are similar in quality to the condensates produced primarily by the country's giant offshore gas fields.

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In addition to crude oil and condensate production, Australia produces natural gas liquids (NGLs) in the form of naturally occurring liquefied petroleum gas (LPG).

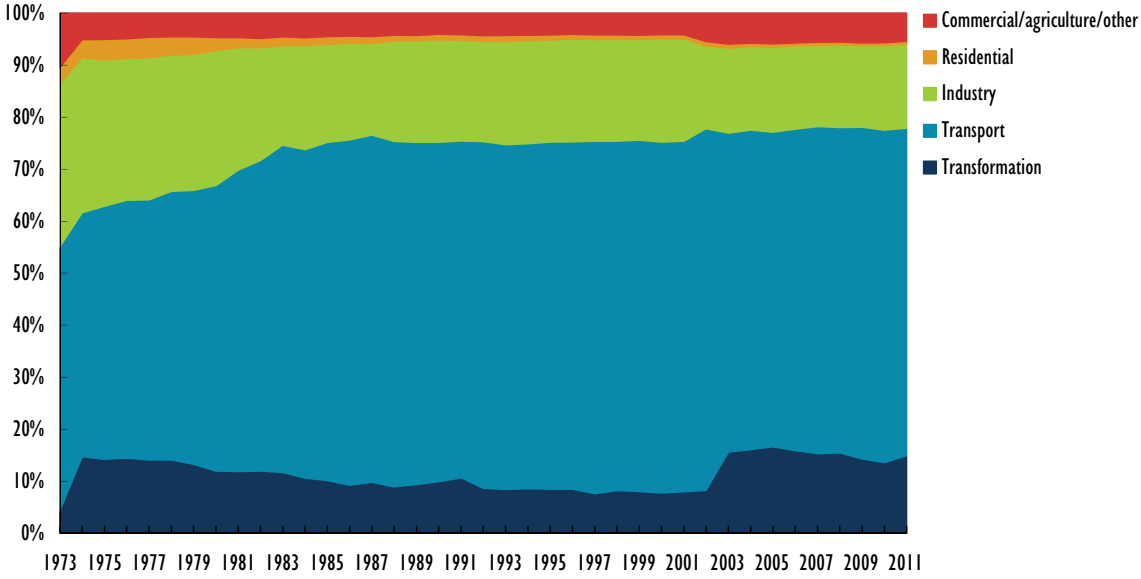
Total Australian crude oil and condensate production peaked in 2000 at some 687 kb/d. Production has since declined and averaged around 410 kb/d in 2012 (an additional 70 kb/d of LPG was also produced in 2012). On average, the downward trend is expected to continue as older fields mature and slowly decline.

In the outlook for the longer term, Australia's crude oil and NGLs production is projected to decline at an average rate of 3.8% annually to 2050. This does not include any potential future production from significant unconventional oil resources. Production of naturally occurring LPG is projected to increase at an average annual rate of 0.4% in the period to 2050. Over the same period, consumption of petroleum products is expected to grow at an average annual rate of 1.1%. Total net imports of liquid fuels are projected to increase by 2.1% a year.

Oil demand

Oil demand in Australia averaged 1 126 kb/d in 2012, up from 1 060 kb/d in 2010. Total oil use has grown at an annual average rate of around 1% since 2000. The transport sector, which accounts for nearly two-thirds of all oil used in Australia (63% in 2011), has been the primary factor leading oil demand growth. In addition, the mining sector – where diesel is the primary fuel used – has continued to expand in Australia and also contributed significantly to an increase in diesel demand.

Figure 4.1.2 Oil consumption by sector, 1973-2011



Diesel surpassed gasoline as the largest single component of the country's total oil demand in 2010. It accounted for 36% of the country's total oil demand in 2012, up significantly from 25% in 1998. Gasoline stood at 28% of total oil demand in 2012, down from 36% in 1998.

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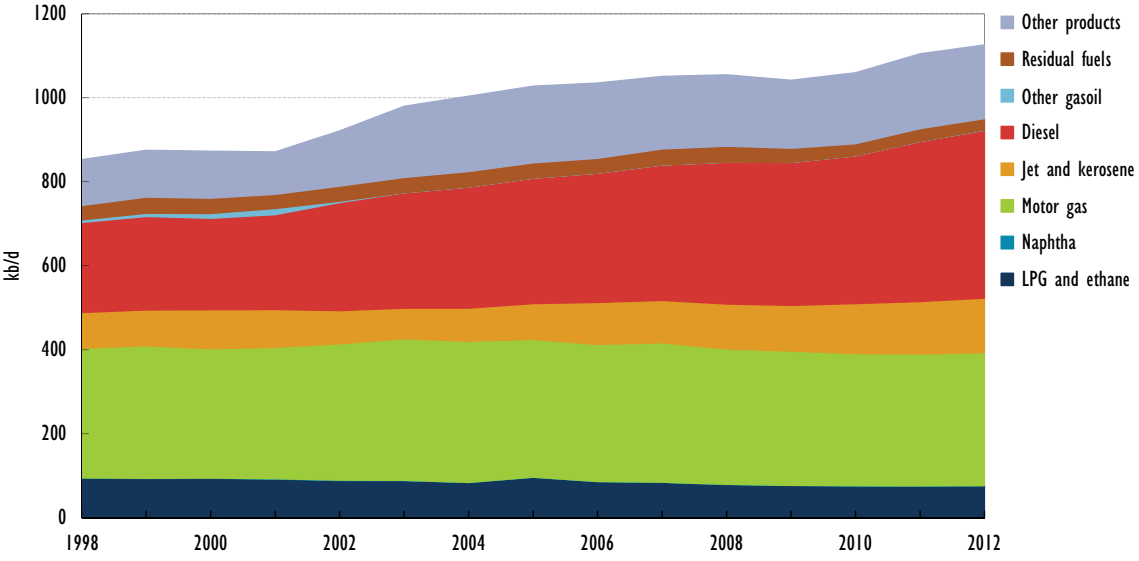
Figure 4.1.3 Oil demand by product, 1998-2012



Imports/exports and import dependency

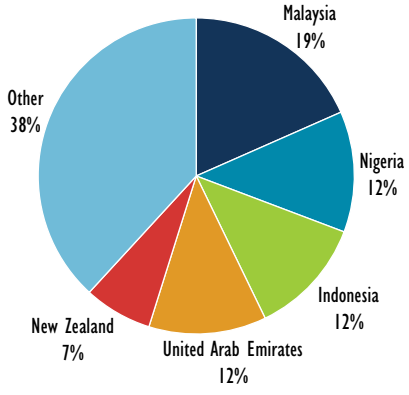
Australian net oil imports averaged 646 kb/d in 2012, up from 614 kb/d in 2011 and 482 kb/d in 2005. Until 2000, the year in which its domestic crude production peaked, Australia was either a net oil exporter or relied only marginally on oil imports to meet domestic demand.

A large portion of Australia's domestic crude oil production is exported, as the quality of the oil and its geographic location of production (coming primarily from the northwest coast) makes it attractive for Asian refineries.

At the same time, the majority of domestic refinery capacity is located close to the major demand centres on the east coast, where refiners process primarily domestic crudes coming from the southeastern fields and lower-quality imports from Southeast Asian producers. In 2012, total imports of crude oil amounted to some 499 kb/d, primarily sourced from Malaysia, Indonesia, Nigeria and the United Arab Emirates (UAE).

Imports of refined products have also steadily increased in recent years, rising from just under 200 kb/d in 2004 to 379 kb/d in 2012. Australian product imports in 2012 included 245 kb/d of middle distillates, and were sourced predominantly from Singapore (51%), followed by Korea (16%) and Japan (9%).

Figure 4.1.4 Imports of crude oil by origin, 2012



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Oil company operations

While there are many oil companies with upstream activities in Australia, four companies account for the vast majority of Australia's domestic oil production: Woodside, ExxonMobil, BHP Billiton and Apache. Regarding downstream activities, there are four companies operating Australia's six refineries: BP, Caltex, ExxonMobil and Shell.

Oil supply infrastructure

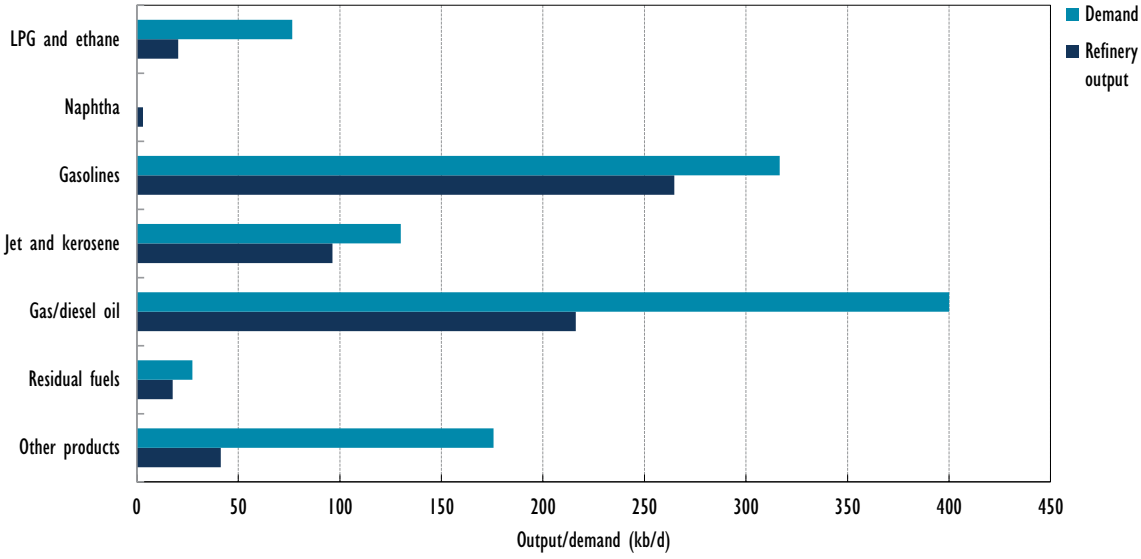
Refining

There are six refineries in Australia, with a total crude distillation capacity of 680 kb/d. While mostly constructed in the 1950s and 1960s, these have undergone extensive upgrading, in particular in 2005-06. Australia's refineries are relatively small by global standards, with the largest, the Kwinana refinery (south of Perth), at just over 142 kb/d, representing roughly 21% of the country's total distillation capacity.

Australian refineries face considerable competition from mega-refineries in Asia, with Singapore product prices largely determining their profitability. There have been two Australian refinery closures in recent years. In 2003, Port Stanvac (75 kb/d) in Adelaide was mothballed for economic reasons. Its owner, Mobil, decided to demolish the refinery and remediate the site in 2009. In October 2012, Shell ceased refining operations at its Clyde refinery (82 kb/d) near Sydney and turned the plant into a fuel import terminal.

Australian refineries use both domestic and imported crude, primarily from the country's Bass Strait production in the south and from Southeast Asian producers. Over two-thirds of Australia's refinery input requirements came from imports.

Figure 4.1.5 Refinery output vs. demand, 2012



Refiners produce mostly gasoline and middle distillates, as well as smaller volumes of bitumen and LPG. In 2012, motor gasoline accounted for 40% of refinery output, diesel for 33% and jet fuel and kerosene for 15%.

Ports and pipelines

Australia has three main trunk lines for transporting oil and oil products by pipeline. The company Epic Energy operates a pipeline carrying crude oil and a mixture of NGLs

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659 kilometres (km) from Moomba to Port Bonython. Santos operates the Mereenie to Alice Springs line that covers 270 km. In addition, ExxonMobil operates the Longford to Long Island Point pipeline (southeast of Melbourne), which runs for 190 km.

Australian exports of crude oil and condensate are increasingly sourced from the west coast, while exports of refined product are largely sourced from the east coast. In addition to the six refineries which have port facilities for importing crude oil and exporting refined products, Australia has 58 refined product import terminals. Of these, 11 are major deepwater ports which also have facilities to export petroleum liquids. The port at Fremantle in Western Australia, near Perth, is the country's largest oil exporting centre.

Storage capacity

All storage capacity in Australia is held commercially within the supply chain.

According to IEA figures, the level of crude oil and product stocks held in Australia in 2012 was 38 million barrels (mb), down from 42 mb in 2011. However, while these figures represent the latest available data they do not include all storage capacity in the country, as information from smaller industry participants and independent importers is not always included in the data.

Decision-making structure

The Minister for Industry is responsible for co-ordinating emergency response in the event of an oil supply disruption. The Department of Industry, which has responsibility for the energy portfolio, functions as the permanent core of the national emergency strategy organisation (NESO). In a disruption, this core would expand to include NOSEC, which is composed of representatives from Australian state and territory governments (which have constitutional authority for energy emergencies within their jurisdictions), as well as from industry and the Australian Institute of Petroleum. The NOSEC manages the National Liquid Fuel Emergency Response Plan (NLFERP) which details how Australian governments would respond to a fuel disruption with national implications.

In the event of a disruption, the minister would initially consult with NOSEC to assess potential implications and appropriate response measures. The minister would also consult with other relevant Commonwealth Government agencies including the Department of the Prime Minister and Cabinet, the Department of Foreign Affairs and Trade, the Treasury and the Office of National Assessments.

The Governor-General may, when circumstances require, declare a national liquid fuel emergency under the Australian government's Liquid Fuel Emergency Act of 1984 (LFE Act). Such a declaration must be made by way of proclamation, upon the recommendation of the minister. A national emergency can only be declared if the Governor-General is satisfied that the situation meets the following criteria: the use of emergency powers is in the public interest; there is no real prospect of averting the shortage through voluntary augmentation of supplies by oil companies; and the minister has provided the opportunity for prior consultation with the relevant ministers for energy in all Australian states and territories.

Stocks

Stockholding structure

Australia does not impose minimum stockholding requirements on oil companies, nor does it have public stocks; all oil stocks in Australia are held by industry on a commercial basis.

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The Australian government does have statutory powers over industry stocks in a declared state of emergency under the LFE Act. The Act also empowers the Commonwealth Minister responsible for energy to impose specific reporting and establish stockholding requirements on industry, including in the planning stages prior to a declared state of emergency.

Crude or products

Australia's industry held some 39 mb of oil stocks at the end of April 2013, 32% of which consisted of crude oil.

Location and availability

All Australian oil stocks are held on Australian territory. Australia has a bilateral agreement with New Zealand, where Australian oil companies may tender and hold stocks on behalf of the New Zealand Government with a guarantee that Australia will not impede the release of these stocks to New Zealand. However, no stocks were held under the Australia-New Zealand bilateral agreement in 2012.

Monitoring and non-compliance

Companies report stock levels to the Australian government on a monthly basis through the Australian Petroleum Statistics collection. If necessary, more frequent reporting of stock levels could be implemented to monitor compliance with a directive issued under the LFE Act. The Act also sets out penalties for failure to comply with reporting directives.

Historically, Australia has been a relatively minor net importer, and an occasional net exporter of oil. Therefore, Australia's commercial stockholdings were more than adequate to meet the IEA obligation. Beginning around 2001, declining domestic oil production coupled with oil demand growth has resulted in a steady rise in net imports, and thus assured the amount of oil stocks necessary to meet Australia's IEA obligation.

Stock drawdown and timeframe

Australia's major industry suppliers of petroleum products are represented on NOSEC by their national supply managers. Thus, decisions by the Australian NESO in response to a supply disruption would include their close consultation. The role of stocks in the country's overall response would be through their participation with NESO, and any stockdraw would be through the normal supply and distribution system.

Financing and fees

As they are purely commercial stocks, all stockholding costs are managed on a commercial basis.

Other measures

Demand restraint

At the first sign of an oil disruption, the Australian government's policy is to allow market price mechanisms to operate in order to reduce demand, i.e. to allow oil price increases to flow through to consumers. The government would monitor the effect of natural price increases that flow from the supply disruption on patterns of demand without intervening in the market.

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If price increases did not lead to an adequate decline in consumption, the Australian government would pursue a voluntary, industry-based bulk rationing strategy. This would involve seeking the co-operation of industry to voluntarily place its large consumers and retailers on allocation systems, e.g. fuel purchasers would be able to purchase a set percentage of their normal fuel purchases. Allocations usually commence at 100% of allocation by removing spot sales (which account for 5%) from the market. This approach considers that the use of voluntary, industry-based measures to influence bulk sales is an efficient and effective response tool that would reinforce the normal operations of the market and minimise government intervention.

The National Oil Emergency Demand Restraint Strategy (NOEDRS) establishes the purpose and principles of Australia's demand restraint strategy. It provides a range of light-handed demand restraint measures, supported by policies and procedures, to complement industry initiatives and build on incentives created by price pass-through. The NOEDRS extends options available to Australia by introducing a list of actions which can be utilised to complement market-based mechanisms, including the promotion of eco-driving, corporate information campaigns, carpooling campaigns and public transport campaigns.

Where a further government response to a fuel supply shortage is required, measures would focus on regulatory controls which could be placed on either bulk or retail sales of petroleum products and further demand-side management responses with the objective of reserving supplies for essential users and ensuring that other users have petroleum supply for as long as possible.

Fuel switching

The Australian potential for reducing oil use through fuel switching – from oil to coal or natural gas – in power and heating plants is limited. Oil is only a minor input fuel for electricity generation in Australia, accounting for 1.2% of total electricity generation.

Other

Short-term surge production capacity in Australia is considered inconsequential. Around 95% of Australia's crude oil production (including condensate) is from offshore production facilities. While it may be technically possible to achieve small increases in production from some of these offshore facilities within a 30-day period, it would not be possible to achieve an increase that would alleviate a short-term production crisis in a meaningful way.

Gas

Market features and key issues

Gas production and reserves

Australia's total natural gas production was some 53.9 billion cubic metres (bcm) in 2012, up from 48.4 bcm in 2010. Roughly two-thirds of domestic production came from Western Australia, primarily linked to liquefied natural gas (LNG) projects sourced from the Carnarvon Basin. Gas production in Western Australia has grown substantially in recent years.

Over the medium term, the production of gas is expected to continue to rise as developments now under construction or in the advanced stages of planning are

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completed. Total production is forecast to exceed 140 bcm by 2018. The Australian government's long-term outlook is for gas production to reach nearly 220 bcm by 2030.

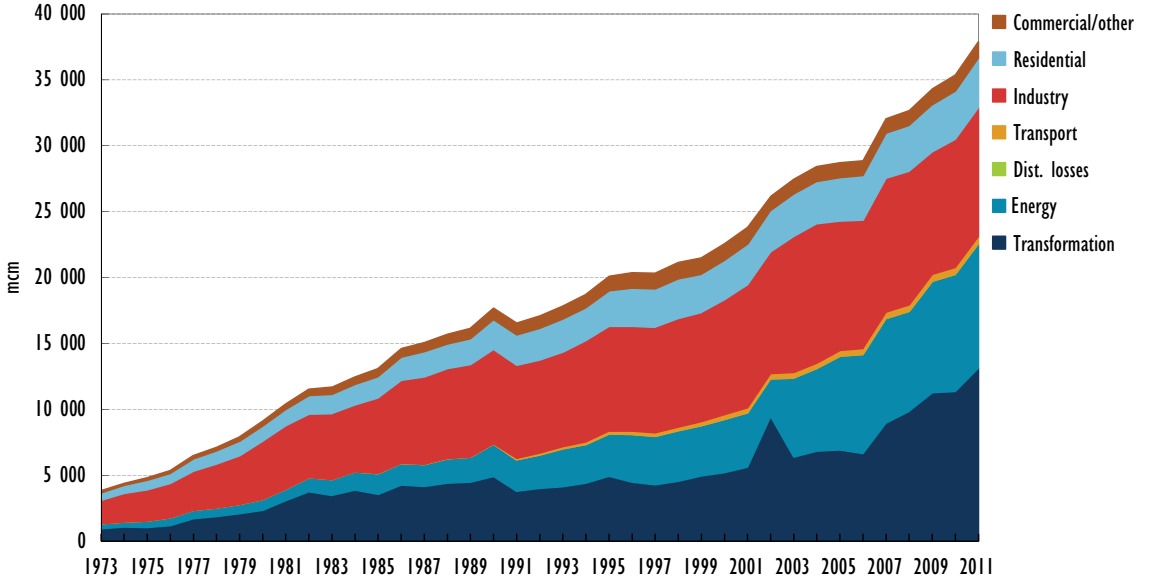
Australia has significant volumes of natural gas reserves that are increasingly being developed both for domestic use and for LNG exports. Around 90% of estimated recoverable reserves of conventional gas are located in the Carnarvon, Browse and Bonaparte basins off the northwest coast. In addition to conventional gas resources, there is growing commercial utilisation of Australia's resources of coal seam gas (CSG). Most of these resources are located in the black coal deposits of Queensland and New South Wales. Tight gas accumulations are located onshore in Western Australia, Queensland and South Australia, while potential shale gas resources are located in the Northern Territory, Queensland, South Australia and Western Australia.

Identified conventional gas resources have increased threefold over the past 20 years while identified CSG resources have grown substantially in recent years. Combined, these identified resources were in the order of 11 trillion cubic metres (tcm) or 431 706 petajoules as of April 2012, the equivalent to roughly 184 years of gas at production rates at the time of the estimate. Potential undiscovered resources and inferred CSG (resources that can be expected to exist based on geological formations but requiring further appraisal) are substantial and could add significantly to total identified reserves in the future.

Gas demand

Domestic gas consumption in Australia totalled some 48.7 bcm in 2012, compared to 35.4 bcm in 2010. In 2011, the transformation sector accounted for 35% of total gas demand, followed by the industry sector with 26%. The industry sector includes metal product industries (mainly smelting and refining activities), the chemical industry (fertilisers and plastics) and the cement industry. In third place, some 25% of gas was consumed in the energy sector, which includes amounts consumed in the production of LNG. The residential sector, characterised by a large number of small-scale consumers where uses of gas include water heating, space heating and cooking, accounted for 10% of total gas consumption.

Figure 4.1.6 Natural gas consumption by sector, 1973-2011



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Gas-fired electricity generation has been the largest factor driving domestic natural gas consumption during the period from 2004 to 2013. The rate of growth for natural gas consumption during this period was 4% annually. The share of gas-fired electricity has increased in recent years, accounting for an estimated 19.3% of electricity generation in 2011/12, compared to 9.8% in 2005/06.

Natural gas demand is projected to continue to grow, reaching 55 bcm by 2018.

Gas import dependency

Australia is a net exporter of natural gas. In 2012 the country produced 48.2 bcm of natural gas which, once domestic demand of 28.9 bcm is taken into account, left a surplus of 19.3 bcm available for export. Australia also imported an additional 10.9 bcm of gas via pipeline from Timor Leste, which it then re-exported through the Darwin LNG terminal.

All Australia's natural gas exports are exported as LNG. Australia exported a total of 30.3 bcm of natural gas in 2012, up from 25.5 bcm in 2011 and 24.7 bcm in 2010. In 2012 the country became the third largest supplier of LNG in the world after Qatar and Malaysia.

Gas company operations

The Australian gas industry comprises around 150 gas companies active in different parts of the gas value chain. After the 1990s, large parts of the gas industry were privatised. While some state and territory governments still have interests in gas retail companies, there is no local, state or Australian government ownership or shareholding in the upstream sector.

In the 1990s, vertically integrated gas utilities were disaggregated and most government-owned transmission pipelines were privatised. If transmission pipelines are determined to be anti-competitive, they are regulated under the National Gas Law and National Gas Rules. Major transmission pipeline companies include the APA Group, Jemena and Epic Energy.

The major gas distribution systems in Australia are privately owned but regulated by government to ensure gas can be transported on reasonable terms by third parties. There is some duplication among companies owning transmission and distribution networks, including Jemena and APA Group.

Gas supply infrastructure

Ports and pipelines

Australia has three LNG terminals (as of the end of 2012) with a combined capacity of 33.2 bcm annually. These are: the Darwin LNG terminal in the Northern Territory; the NorthWest Shelf LNG terminal in Western Australia; and the 5.9 bcm Pluto LNG terminal that came on line in 2012, also in Western Australia.

A major expansion of Australia's LNG export capacity is underway, with an additional seven LNG terminals under construction as of May 2013. These terminals, with a combined capacity of around 83 bcm, are scheduled to come on line between 2014 and 2018.

In addition to its three LNG export terminals, Australia also has a single international natural gas pipeline. This pipeline supplies the Darwin LNG terminal with natural gas imported from the Joint Petroleum Development Area (JPDA) with Timor Leste (10.9 bcm in 2012). (Australia's gas production statistics exclude production from the JPDA).

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Domestically, Australia has more than 33 000 km of high-pressure steel pipelines, of which more than 25 000 km are used for natural gas transmission. The country is divided into three separate gas markets: the eastern market (Queensland, New South Wales, Australian Capital Territory, Victoria, South Australia and Tasmania); the western market and the northern market. These markets are geographically isolated from one another, making transmission and distribution of gas between markets generally uneconomic, and as a result there is no interconnection between them. Australia's natural gas production is therefore either consumed within each market or exported as LNG.

Storage

There are four underground natural gas storage facilities operating in Australia and one LNG peak shaving plant – with a total working capacity of 1.3 bcm. The combined peak output capacity from Australia's natural gas storage facilities is around 20 million cubic metres per day (mcm/d).

The country's underground gas facilities are widely distributed – with facilities in Victoria, Western Australia and the Cooper Basin which straddles western Queensland and South Australia. However, the majority of Australia's gas storage capacity (over 1.1 bcm) is located in the eastern market as this region is the most prone to seasonal variations in demand caused by increased heating demand during winter. The Dandenong LNG storage facility in Victoria provides peak shaving and security of supply services for the Victorian transmission system as well as supporting wholesale trade in LNG used as fuel for transport vehicles.

Storage facility contracts and terms of access are worked out on a confidential bilateral basis between storage providers and customers. No public storage is held by the Australian government and access to storage facilities is not regulated.

Emergency policy

The management of temporary gas shortfalls is primarily undertaken by gas market participants and jurisdictional governments, depending on the nature and size of the event. For larger issues, each state and territory has legislation which confers emergency powers which may be exercised in natural gas emergency situations affecting only one jurisdiction.

In the case of a major gas crisis affecting more than one jurisdiction, the NGERAC will advise energy ministers across jurisdictions. The NGERAC is chaired by a representative of the Commonwealth, and includes government representatives from each jurisdiction as well as industry representatives. This includes producers, transmission system owners and operators, retailers, wholesale market operators, distribution network owners and operators, and major gas users.

NGERAC was developed following the Memorandum of Understanding (MoU) agreed to in 2005 by the former Ministerial Committee on Energy (now the Standing Committee on Energy and Resources (SCER)). The MoU set out a National Gas Emergency Response Protocol which seeks to provide for more efficient and effective management of major natural gas supply shortages. The protocol provides guidance to gas suppliers, gas retailers, the natural gas market operator, and state and territory jurisdictions on their roles and responsibilities during natural gas supply shortages. The protocol recognises the need for commercial arrangements among gas suppliers and users to balance gas supply and demand and maintain system integrity for timely management of natural gas supply shortages. Government intervention in the market would occur as a last resort.

The legal framework for natural gas is the National Gas Law 2008. Additionally, the National Gas Rules govern access to natural gas pipeline services and elements of

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broader natural gas markets. The rules have the force of law and are made under the National Gas Law.

Emergency response measures

Strategic gas stocks and drawdown

There are no strategic stocks of natural gas in Australia, as there are no government stocks or requirements placed on grid owners, system operators or other industry participants to hold minimum reserves of natural gas.

Demand restraint

For larger disruptions affecting only one jurisdiction, each state and territory has legislation which confers emergency powers which may be exercised in a natural gas emergency. For emergency situations that may affect more than one jurisdiction, the NGERAC (or a sub-committee of the NGERAC) would be convened to consider the situation and provide advice to the SCER energy ministers. The SCER ministers, in turn, are able to enact emergency powers within their corresponding jurisdictions. These powers can include issuing directions for production, transmission, distribution and allocation of natural gas.

The NGERAC has rarely been convened, as to date the management of temporary gas shortfalls have been undertaken by market participants, natural gas system operators and state and territory governments, depending on the nature and size of the event.

Fuel switching

There are no policies in Australia to promote fuel switching away from natural gas in an emergency. However during a gas crisis, power plants and large industrial customers can use a number of strategies, including fuel switching.

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Austria

Key data

Table 4.2.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	23.5	19.7	18.9	24.6	24.6	24.6	20.3
Demand (kb/d)	216.9	250.6	299.3	279.4	265.3	258.8	245.6
Motor gasoline	59.1	45.7	48.1	42.2	40.8	39.6	-
Gas/diesel oil	68.3	121.9	167.5	156.9	150.1	149.4	-
Residual fuel oil	39.5	23.5	19.3	14.1	12.5	12.2	-
Others	50.1	59.4	64.4	66.2	61.9	57.6	-
Net imports (kb/d)	193.4	230.9	280.4	254.8	240.7	234.2	225.3
Import dependency (%)	89.2	92.1	93.7	91.2	90.7	90.5	92
Refining capacity (kb/d)	204.0	208.6	208.6	213.2	213.2	213.2	-
Oil in TPES (%)**	42	41	41	37	35	35	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.2.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	1 359	1 904	1 728	1 810	1 776	1 906	1 491
Demand (mcm/y)	6 427	8 114	10 011	10 007	9 447	9 038	8 891
Transformation	2 191	2 452	3 346	3 378	3 192	0	-
Industry	2 460	2 992	3 416	3 299	3 084	0	-
Residential	947	1 398	1 576	1 633	1 449	0	-
Others	829	1 272	1 673	1 697	1 722	0	-
Net imports (mcm/y)	5 068	6 210	8 283	8 197	7 671	7 132	7 400
Import dependency (%)	78.9	76.5	82.7	81.9	81.2	78.9	83
Natural gas in TPES (%)	21	23	24	24	23	24	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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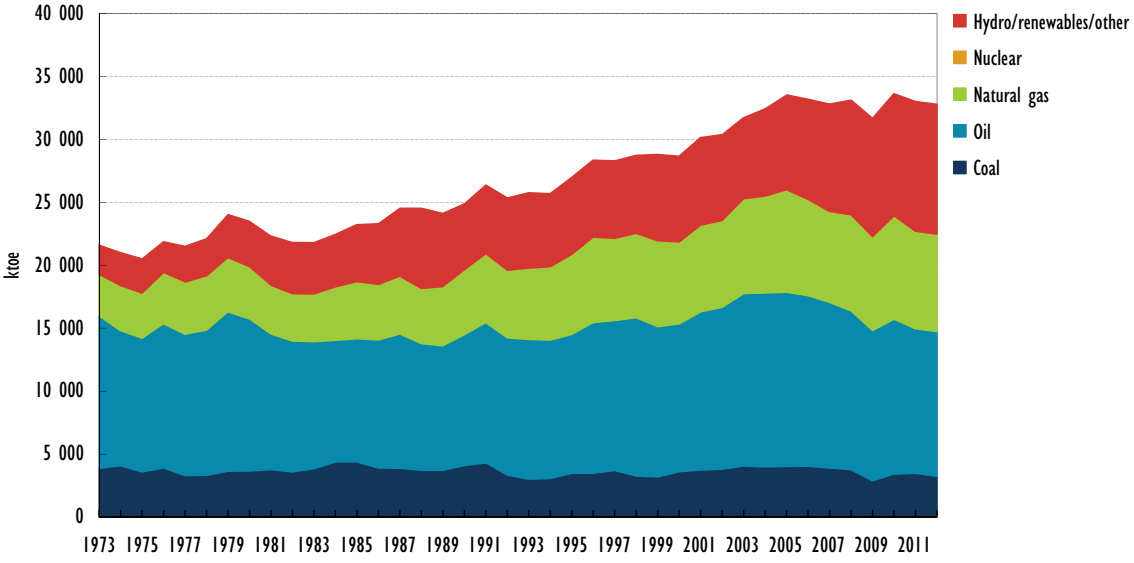
Figure 4.2.1 Total primary energy source (TPES) trend, 1973-2012



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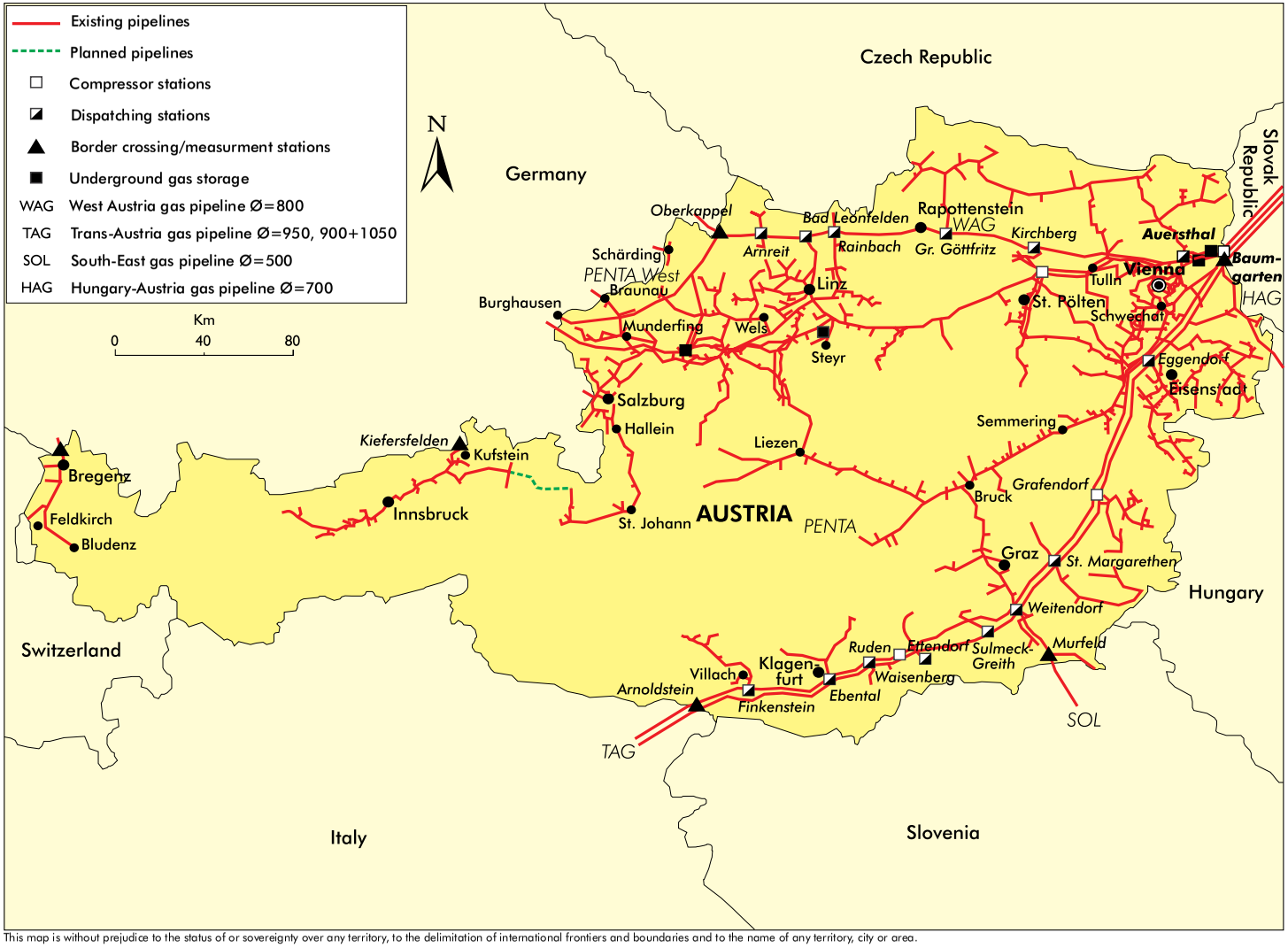
Map 4.2.1 Oil infrastructure of Austria

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Map 4.2.2 Gas infrastructure of Austria



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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Country overview

The Austrian total primary energy supply (TPES) has been increasing steadily since 1973, reaching 32 million tonnes of oil-equivalent (mtoe) in 2012. Although shrinking as a share of TPES, oil remains a significant energy source accounting for 35% of Austria's energy mix. Austrian oil demand peaked in 2005/06 reaching almost 300 kb/d. In 2012 it stood at 259 kb/d. In 2011, 65% of oil consumed fuelled the transport sector. Although Austria has some limited indigenous oil production, representing about 10% of demand in 2012, it is heavily dependent on imports of crude. In 2012, the countries of the Organization of the Petroleum Exporting Countries (OPEC) were the source of 54% of Austrian crude, while countries from the former Soviet Union (FSU) accounted for 44%. In the same year, Austria imported 130 kb/d of refined oil products. Middle distillates accounted for three-quarters of all oil product imports. The vast majority of oil products imported into Austria are refined in neighbouring European countries. Austria's Schwechat refinery, one of the largest inland refineries in Europe, has a capacity of approximately 209 kb/d. It produced 190 kb/d in 2012. Austria is supplied with crude by the Trans-Alpine Pipeline (TAL) which links Trieste (Italy) with Ingolstadt (Germany). At Würmlach, Austria, the pipeline branches out onto the Adria-Wien Pipeline (AWP) which feeds the OMV refinery at Schwechat near Vienna.

The Stockholding Act 2012 guarantees the availability of emergency reserves covering 90 days of net imports and obliges all importers to hold emergency stocks equivalent to 25% of their previous year's net imports plus 10% to account for unavailable stocks. Importers may hold their stocks at the private, non-profit stockholding company ELG (*Erdöl-Lagergesellschaft*) an official licensed stockholding entity, which is privately owned by OMV and three international companies. Currently companies delegate about 97% of their stockholding obligation to ELG.

The share of natural gas in the country's TPES stood at 24% in 2011. Austria's gas consumption increased from 7.0 bcm (19.2 mcm/d) in 2000 to 9.0 bcm (25.0 mcm/d) in 2012. A great majority of the gas consumed in Austria is imported, with the Russian Federation being the main supplier. Austrian indigenous production stood at 21% of 2012 consumption. Currently 34% of the Austrian natural gas consumption is for electricity generation, while 33% goes to industry and 15% is used for residential purposes.

The key elements of Austria's overall gas security policy are large commercial stocks held by all major gas players as well as sufficient storage capacity, currently standing at around 78% of yearly consumption. Austria is well connected to its neighbours through a number of reversible pipelines. the Austrian government does not hold any natural gas stocks.

Oil

Market features and key issues

Domestic oil production

Austria has limited indigenous oil production, representing about 10% of demand, or 24.6 kb/d in 2012. Production has remained relatively stable since 2000 averaging 23 kb/d. Current estimates place Austrian oil reserves at some 14 years at current production levels. Two companies are active in crude oil production: OMV with about 85% of the share of total Austrian crude and NGL production and RAG producing the 15% remaining share.

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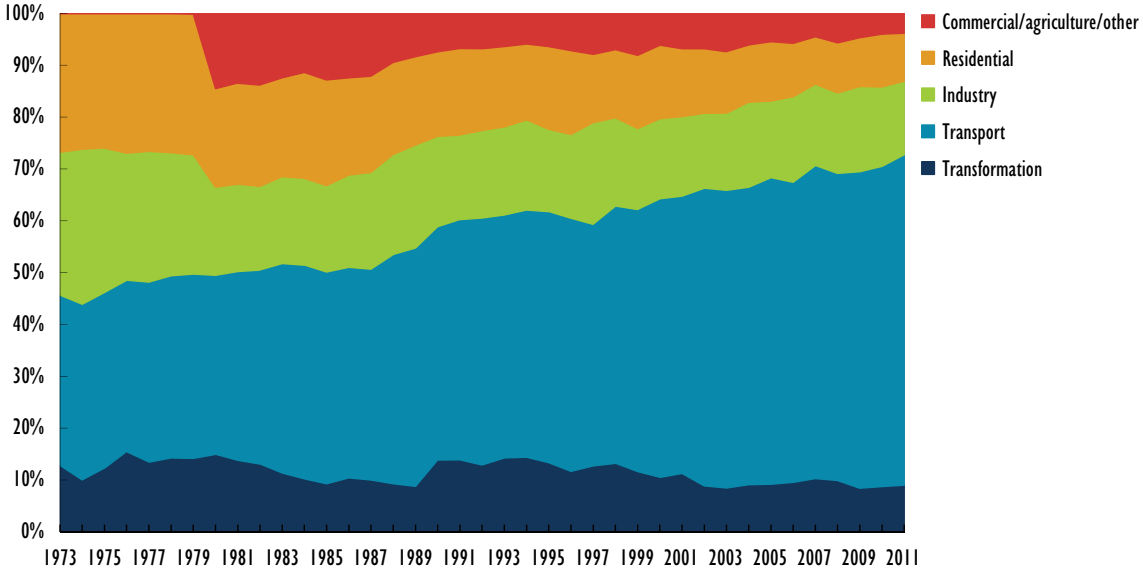
Figure 4.2.2 Oil consumption by sector, 1973-2011

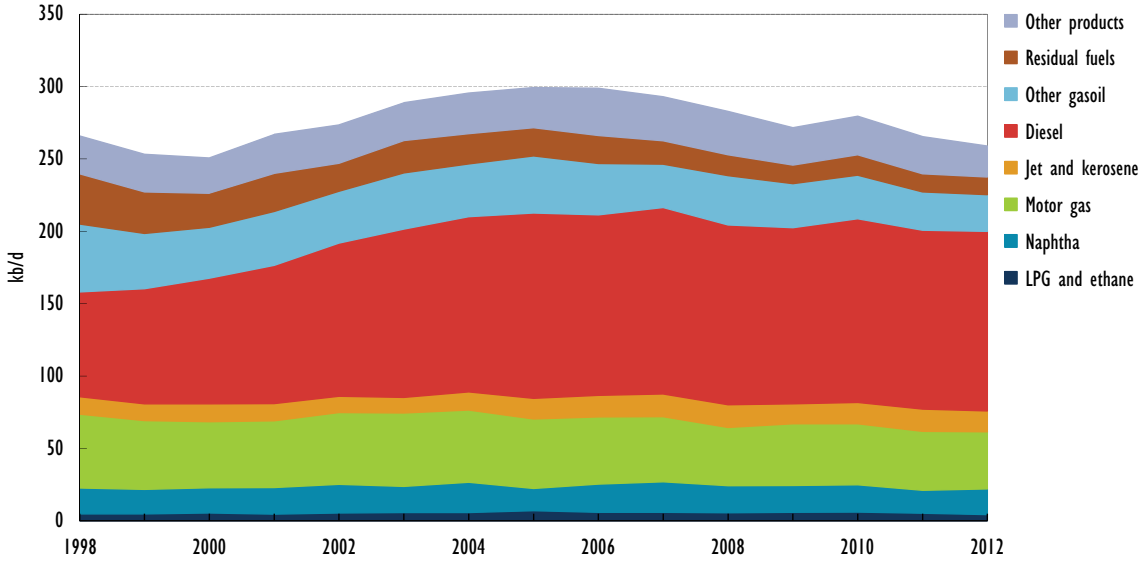


Oil demand

In 2011, the transport sector accounted for 65% of oil demand, followed by the industrial sector with 14% and residential use with 9%. As seen in most member countries of the International Energy Agency (IEA), the share of transport in oil consumption has been increasing rapidly since 1974 when it accounted for about one-third of all oil consumed in Austria. This percentage has grown steadily over the years, reaching 65% in 2011. Conversely, in 1974 the proportion of oil consumption in the residential and industry sectors declined from 27% and 28% respectively.

Oil product demand has fluctuated between 250 kb/d and 300 kb/d since 1997, reaching 259 kb/d in 2012.

Figure 4.2.3 Oil demand by product, 1998-2012



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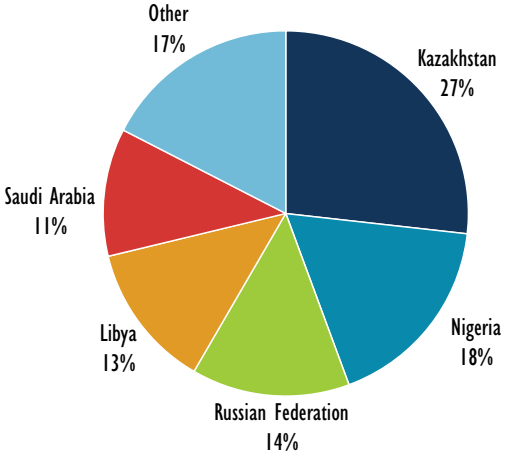
In terms of oil demand by product, as for many European countries, Austria has shown a marked increase in diesel demand. In 2000 it stood at 35%, whereas in 2012 it represented 48%, or 124 kb/d. This represents a 3.8% annual growth rate (or 56% year on year) between 2000 and 2012. It is worth noting that seven out of ten new cars bought in Austria run on diesel, this is partly accountable for the growth in demand. The demand for kerosene and naphtha also expanded in the same period, albeit at a much slower pace, increasing 15% and 3% respectively year on year from 2000. In 2012 they represented 5.5% and 7% of oil product demand, or 14 kb/d and 18 kb/d respectively. Although it still represents a considerable share of Austrian oil product demand, gasoline has decreased by 14% during the same period but it continues to command 15% of oil product demand. Demand for heating oil/other gasoil and residual fuels dropped by 28% and 48% respectively from 2000 to 2012. In 2012, demand for heating/other gasoil was 25 kb/d, while demand for residual fuel was 12 kb/d.

Imports/exports and import dependency

In 2012, Austria's oil imports reached 285 kb/d, consisting of about 150 kb/d of crude oil, 4 kb/d of NGLs and feedstock, and some 130 kb/d of refined products. Austria is highly dependent on both OPEC and countries from the FSU for its crude imports. In 2012, 98% of its crude imports were met by these two blocs, with OPEC representing 54% and the FSU 44%. In 2012, Kazakhstan supplied Austria with 40kb/d of crude or 27% of its imports, followed by Nigeria (18%) and Russia (14%).

Figure 4.2.4 Crude oil imports by origin, 2012



Austria imports about 130 kb/d of refined product. Its neighbouring European countries provide the bulk of its product imports. In 2012, Germany supplied Austria with 48% of its oil products, while the Slovak Republic accounted for 18% of its total imports, followed by Hungary (8%), Italy (8%) and the Czech Republic (7%).

Oil company operations

OMV AG is owned by *Österreichische Industrieholding AG* (31.5%), International Petroleum Investment Company, Abu Dhabi (24.9%) and a number of smaller national and international investors (43.6%). *Rohöl-Aufsuchungs-AG* (RAG) is owned by *RAG Beteiligungs-AG* (100%). *RAG Beteiligungs-AG* is owned by one German and three Austrian energy sector companies.

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Refining

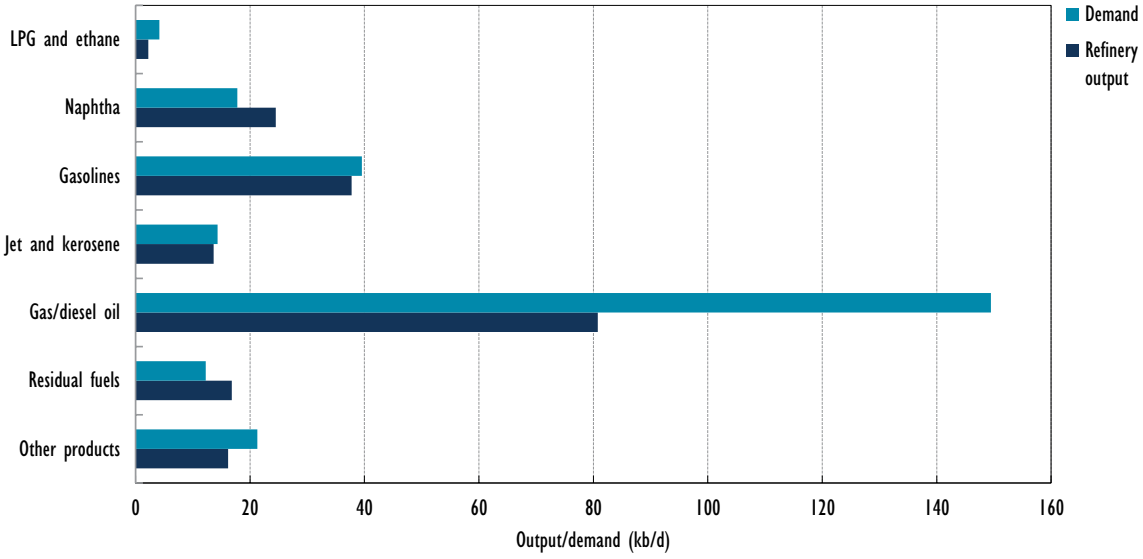
Austria has only one refinery, the Schwechat facility outside Vienna, entirely owned and operated by OMV. It is one of the largest inland refineries in Europe, processing indigenous and imported crude oil and producing a full range of oil products for domestic consumption and export.

This refinery has been under fairly heavy market pressure by nearby refineries in neighbouring countries. In 2011, the Schwechat refinery had a total distillation capacity of around 9.6 million tonnes (about 200 kb/d), with a throughput of 7.7 million tonnes of crude oil (about 155 kb/d). About 20% of its production is exported to neighbouring countries.

At the end of 2011 Austria's total operational refining capacity was 209 kb/d according to official figures, slightly less than the total Austrian demand for oil products which was 261 kb/d. However, the Austrian refining industry is unable to meet distillate demand, with a gas/diesel oil deficit of about 63 kb/d in 2011, and a total distillate deficit of over 65 kb/d. Conversely, the industry had a small gasoline production surplus of 2 kb/d in 2011. Austria's net product imports stood at 78 kb/d in 2011.

Since 2006 this imbalance has worsened as diesel consumption as a share of oil demand has increased from 53.9% in 2006 to 58% in 2012. Between 2001 and 2012, demand for diesel increased by 30% and for and jet and kerosene by 20%, while demand dropped for gasoline (14%) and residual fuel (53%). These trends are expected to continue.

Figure 4.2.5 Refining output vs. demand, 2012



Ports and pipelines

Austria is supplied with crude by the TAL linking Trieste with Ingolstadt and branches out onto the AWP which feeds OMV Schwechat refinery near Vienna. Crude takes approximately 14 days to reach the refinery from Trieste. In 2010 the total throughput of the TAL was 35 million tonnes (approximately 700 kb/d), of which 7.4 million tonnes (or 150 kb/d) were transported by the AWP to the Schwechat refinery. Imported crude oil is transported solely via the TAL and the AWP.

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Austria has one product pipeline which links the Schwechat refinery to the west of the country, and terminates at the St. Valentin storage site. In 2011, the throughput of the Produktenleitung-West Pipeline (PLW) was 1.1 million tonnes.

A crude oil pipeline leading from Bratislava, Slovakia to Schwechat refinery has been under discussion for over a decade. The construction of this pipeline would allow the Austrian refiner to be fed through the southern arm of the Druzhba pipeline while at the same time allowing Slovakia to be supplied in an emergency through the TAL pipeline, via the AWP.

Storage capacity

In 2011, total storage capacity in Austria stood at 6.6 mcm, or around 42 mb of crude and oil products. The storage capacity is almost evenly distributed between crude – 53% (3.5 mcm) and oil products – 47%. The majority of the crude oil storage capacity is located in Trieste. The Schwechat refinery enjoys storage capacity of about 2.4 mb. Most other crude oil storage sites are located along the AWP within easy reach of Schwechat refinery. Apart from Trieste, and the Lobau storage site at Lannach near Graz (3.3 mb) and St. Valentin (2.9 mb of oil products) have the largest storage capacities.

Most of Austria's storage capacity for oil products is located near the refinery and also at the St. Valentin site in the west of the country. Currently Austria is suffering from a considerable lack of distillate storage capacity. In 2011, middle distillate storage capacity stood at 9.2 mb, or 55% of all oil product storage capacity. In an effort to plug the gap in storage capacity for distillates, OMV is rededicating 210 mcm (1.3 mb) of fuel oil capacity to accommodate distillates.

Decision-making structure

One of the main aims of Austrian energy policy has been to reduce its dependence on energy imports and to strengthen its security of supply. Security of energy supply is one of the three pillars in Austria's Energy Strategy. To ensure oil security, Austria has a strong legal framework to deal with energy supply crises. Austria is able to comply with any IEA co-ordinated action if the relevant decisions of the Governing Board are based on articles of the International Energy Program (IEP).

The Stockholding Act guarantees the availability of emergency reserves covering 90 days of net imports and obliges all importers to hold emergency stocks equivalent to 25% of their previous year's net imports plus 10% to account for unavailable stocks. Importers may hold their stocks at the private, non-profit stockholding company ELG, an official licensed stockholding entity, which is privately owned by OMV and three international companies.

Currently companies delegate about 97% of their obligation to ELG. The Austrian national emergency strategy organisation (NESO) is embedded on a stand-by basis in the Department of Energy and Mining of the federal government the federal Ministry of Economy, Family and Youth. During an IEA co-ordinated action, Austria would participate with the release of its ELG stocks.

Depending on the type of domestic crisis, the government considers that stockdraw combined with demand restraint measures would be a suitable response. Measures to restrain oil demand are grouped in three stages, depending on the nature and severity of the crisis, and would mostly concern the transport sector which accounts for 65% of total oil demand. While the initial stage of light-handed measures would mostly focus on public campaigns for voluntary energy saving, medium-handed measures would include compulsory restrictions such as lower speed limits and driving bans, and the final heavy-

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handed stage would rely on coupon rationing for the private sector and allocation for fuel oil use in industry.

The Energy Intervention Powers Act 2012 and the Stockholding Act 2012 were established in 1982 and define the legal framework to respond to oil supply disruptions. These laws define all measures and responsibilities of the relevant national and regional emergency organisations. In times of oil supply disruptions, the Energy Steering Council, consisting of representatives of various ministries, the energy industry and social partners, would act as an advisory body to the Minister for Economic Affairs at the Ministry of Economy, Family and Youth.

Within the federal government, the federal Ministry of Economy, Family and Youth is responsible for contingency planning and energy emergency measures.

The legal framework for Austrian emergency management is the Energy Intervention Powers Act (*Energielenkungsgesetz 2012*) and the Stockholding Act (*Erdölbevorratungsesetz* 2012). All tasks, measures and responsibilities of the national and regional emergency organisations concerned are clearly defined in these laws.

Stocks

Stockholding structure

The regulations of the Oil Stockholding Act 2012 as well as the former Oil Stockholding and Reporting Act 1982 guarantee the availability of 90-day emergency reserves at all times. All importers are obliged to hold 25% of their previous year's net imports, plus 10% for unavailable stocks, as emergency stocks. Only 3% of Austria's emergency stocks are held by the compulsory stockholders themselves. According to the regulations of the Energy Intervention Powers Act the Austrian authorities have control over all stocks (compulsory and industry stocks) in crisis situations.

Austria implemented the IEP, opting for a market-based stockpiling system in preference to a centralised approach. The Stockholding Act therefore offers Austrian importers a number of options for meeting their stockholding obligations. One of these is transferring their obligation to a storage operator like ELG, which is defined by the new Stockholding Act as the Austrian Central Stockholding Entity (CSE). To fulfil its task and hence Austria's international stockholding obligations ELG is backed by a state guarantee.

Crude or products

The breakdown of stocks by crude and petroleum products as of 30 April 2012 was as follows:

Crude oil	1.015 million tonnes (approximately 7.5 mb)
Gasoline	0.371 million tonnes (approximately 3.1 mb)
Middle distillates	0.994 million tonnes (approximately 7.5 mb)
Fuel oil	0.310 million tonnes (approximately 2.0 mb)

Location and availability

The stocks held by the company are dispersed among tank farms throughout Austria. In addition, some are held at the Trieste oil terminal.

Because of the pattern of available tankage capacity, most of the stocks are located in the east and south of Austria. However, the logistics systems in place assure rapid access to emergency stocks for western Austria, as confirmed by a 2008 study of the availability of logistics systems in the event of a crisis.

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ELG's primary task is to hold stocks that match the market's needs at all times. Holding crude and product grades that meet market requirements is an important aspect of ELG's inventory management approach. This is achieved by replacing some crude and product grades that will cease to be marketable in the medium term by others that will continue to be saleable for longer periods. For instance, some product stocks are exchanged in order to maintain marketable quality and to prevent future financial losses.

Emergency stocks are not held separately from commercial stocks. All oil products held by ELG are commingled stocks.

Monitoring and non-compliance

The federal Minister of Economy, Youth and Family may monitor the level of compulsory emergency reserves, their specifications, and the characteristics and equipment of the storage facilities at any time during normal business hours. The inspectors must be granted unrestricted access to the storage facilities and all inventory records during normal business hours. Inspections may include the taking of samples, which must be permitted within reasonable limits. To monitor effectively, the inspectors may have recourse to the general state administration and consult with or engage suitable experts. Representatives seconded by the European Commission may also participate in these inspections.

Stock drawdown and timeframe

Intervention measures (e.g. a release of stocks) may only be taken under the Energy Intervention Powers Act to carry out the following:

1. to avert imminent or overcome actual disruptions of Austrian energy supplies insofar as these:
   a) do not represent seasonal shortages
   b) cannot be averted or overcome in a timely manner or at reasonable cost by market-based measures or
2. to take emergency measures pursuant to decisions by the governing bodies of international organisations where this is necessary to fulfil obligations under international law.

Intervention measures are taken by order of the federal Minister of Economy, Family and Youth and, unless they relate exclusively to the total or partial revocation of intervention measures, these orders require the assent of the Main Committee of the National Council. Orders imposing intervention measures regarding energy products, safeguarding electricity supplies and safeguarding gas supplies are, without exception, enacted separately of each other. In case of urgency, orders requiring the agreement of the Main Committee of the National Council are enacted simultaneously with the application for the committee's assent.

The Austrian stockholding system allows for an immediate delivery of released stocks. Stocks are sold at market price and distribution is arranged according to product, facilities and activities of the market participants.

Financing and fees

Austria has only above-ground storage sites for oil. Costs of emergency stockholding are born by the consumers. Actual values are:

- gasoline: € 11.21/1 000 litres
- diesel: € 12.42/1 000 litres
- fuel oil: € 11.18/t.

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The stockholding rates are announced annually in the official gazette supplement of the *Wiener Zeitung*. ELG focuses on maintaining a well-balanced rate-setting policy that enables ELG to significantly mitigate the price risk associated with stock builds.

Other measures

Demand restraint

Depending on the kind of domestic crisis, Austria considers that stockdraw combined with demand restraint measures would be a suitable response. Demand restraint measures range from light-handed to heavy-handed, and would be phased in three stages, depending on the nature and severity of the crisis. In the initial stage, priority would be given to light-handed measures in the form of public information campaigns and public appeals for voluntary energy saving. In the next two stages, medium-handed and heavy-handed measures would also be considered.

Fuel switching

In Austria there are 583 thermal power stations with a total output of 8 249 MW; eight of them are fired with oil derivatives. Their total output is 362 MW (4% of the total output of Austria's thermal power plants). These plants have only a hypothetical potential for fuel switching, although power plants are still obliged to hold 30 days' worth of supplies as reserves. In Austria many households can switch their heating systems from oil to biomass (mainly wood). As oil products are mainly used in the transport sector, short-term fuel switching is not a real option for Austria in response to an oil supply disruption.

There are no policies or legislation available to promote short-term fuel switching. Fuel switching would take place on a voluntary basis by the operators of power plants. According to the regulations of the Energy Intervention Powers Act, in periods of crisis the industries involved are obliged to perform additional monitoring and submit reports.

Other

During a crisis the Energy Intervention Powers Act also allows the Minister of Economy, Family and Youth to relax product specifications for a limited period, subject to approval by the Ministry of Agriculture, Forestry, Environment and Water Management. The most likely modifications could allow a higher benzene content in gasoline and a higher sulphur content in heating oil and gas oils.

Gas

Market features and key issues

Gas production and reserves

Natural gas accounted for 24% of Austria's TPES in 2012. In 2012, its natural gas production stood at 21% of consumption or 1.9 bcm. Production as a proportion of total consumption has been dwindling since the 1960s and is expected to continue declining, satisfying only about 10.5% of consumption by 2030. Proven natural gas reserves as of 1 January 2013 were estimated at 20.6 bcm. Therefore the large majority of natural gas consumed in Austria is imported. Similarly to oil, two companies are active in natural gas extraction: OMV with 87% of production and RAG with the remaining 13%.

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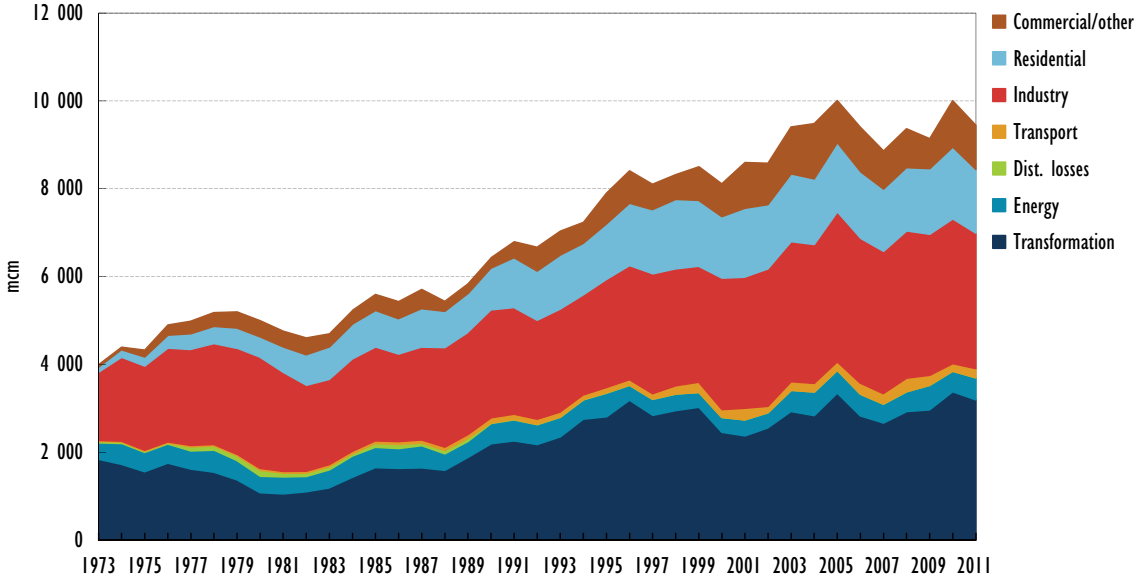
Gas demand

Austrian demand for natural gas has been increasing steadily since the 1970s at an average annual rate of 2.5% (from 1973 to 2010). Although it declined slightly between 2006 and 2009 from its peak of 10 bcm (2005), consumption recovered in 2010, reaching 9.5 mcm, and fell again in 2012 to 9 bcm.

The transformation sector continues to be the largest consumer of natural gas in Austria, representing about 34% of the country's total gas consumption in 2011. Its share in consumption has been more or less constant during the decade from 2002 to 2011. Industry also continued to account for 33% of gas demand in 2011, while residential demand increased from 3% in 1973 to 15% in 2011. In Austria, demand peaks in winter when gas consumption significantly increases for heating. Daily peak gas demand in 2012 stood at some 55 mcm/d.

Figure 4.2.6 Natural gas consumption by sector, 1973-2011



Gas import dependency

The bulk of Austria's gas imports come from Russia. In 2012, almost three-quarters (71%) of Austrian natural gas imports came from Russia or the FSU. Austria started to diversify its source of imports in the early 1990s; since then its natural gas imports from Norway have been increasing steadily. But while gas imports on a contractual basis show some diversity of supply sources, in terms of physical delivery all gas used in Austria originates in Russia.

Security of supply is of particular importance in Austria, as there is still a very strong dependence on Russian gas, which accounts for a large proportion of total demand. The Austrian government is working towards reducing this dependency by actively participating in the efforts of the European Union to complete the internal gas market and to implement infrastructure projects that have been identified to be of common interest. Apart from creating increased competition, this should lead to the diversification of sources of and supply routes for natural gas.

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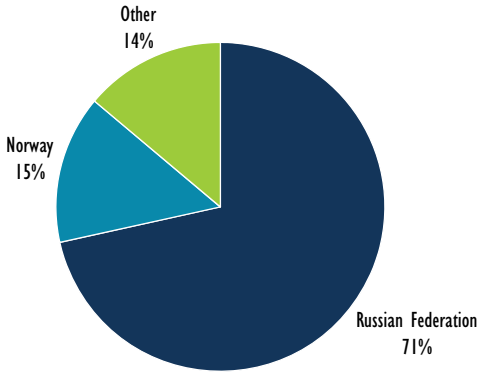
Figure 4.2.7 Natural gas imports by source, 2012



Gas company operations

Six companies currently import gas into Austria on the basis of long-term supply contracts. The Austrian gas grid is operated by three transmission system operators (TSOs) – Gas Connect Austria GmbH, BOG GmbH and TAG GmbH – and 22 distribution system operators. There are 39 gas suppliers operating in Austria.

The market was fully liberalised in October 2002, but switching rates remain low, and real competition has not yet fully emerged. E-Control and the Austrian Competition Authority jointly provide supervision of competition issues in the sector. Competition is expected to increase with the implementation of the Third Internal Energy Market Package in Austria, adopted in 2009. The new market model provided for in the new legislation became operational as of 1 January 2013.

Gas supply infrastructure

Ports and pipelines

The total length of gas pipelines in Austria is 40 928 km, of which 3 210 km is transmission pipeline and 37 718 km is distribution pipeline. Austria is connected to the European gas grid through the Baumgarten hub where a number of pipelines converge, directly connecting Austria to Germany, Italy and Hungary.

Austria is an important transit country for gas, with significant gas transit to Hungary and Italy; it hosts the principal gas hub in the region at Baumgarten. Domestic transmission pipelines are owned and operated by OMV Gas, EVN Netz GmbH, Gasnetz Steiermark GmbH, OÖFG. BEGAS is managed by AGGM (Austrian Gas Grid Management).

Following Article 6(5) of EU Regulation No 994/2010, Austria has implemented bi-directionality in four of its interconnections at Baumgarten, Oberkappel, Überackern and Arnoldstein, and has requested exemptions to this article for two connections to Hungary and Slovenia. The increasing peak demand may cause supply disruptions in case of a failure of the import infrastructure during a peak demand period. However, the risk analysis conducted in the context of the implementation of Regulation (EU) No. 994/2010 showed that Austria meets infrastructure standard N-1, scoring 178.8%.

Storage

Austria enjoys considerable storage capacity. In July 2012, total capacity from its nine sites stood at about 7.4 bcm, or 78% of 2010 natural gas consumption. OMV owns three

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facilities with a total capacity of 2.4 bcm, or 39% of total capacity, while RAG owns 19%; the rest is owned by various companies (Astora, Gazprom and E.ON).

Total output capacity from gas storage sites is 3.2 million cubic metres per hour (mcm/h). This is slightly higher than the 2.5 mcm/h of peak winter demand experienced during the cold spell of February 2012.

Emergency policy

The key elements of Austrian gas security policy are sufficient storage capacity, diversification of supply sources and routes and flow reversibility of its gas pipelines. Although Austria does not have government gas stocks, it does have large gas storage capacity of commercial stocks.

Emergency response measures

Austria's considerable commercial natural gas storage capacity gives it a significant buffer during a gas supply shortage. The Natural Gas Act 2011 is one of the three pieces of legislation cited as a legal basis for Austria's natural gas policy. The key piece of legislation stating the government's power in dealing with gas supply emergencies is contained in Section 20j of the Energy Intervention Powers Act, which states that the government is tasked with:

1. giving directions to natural gas undertakings, controlling area managers, balancing group representatives, balancing group co-ordinators and producers regarding the production, transportation, transmission, distribution, storage, wholesaling and retailing of natural gas
2. giving instructions to final consumers regarding the allocation, withdrawal and use of natural gas, and preventing consumers from withdrawing natural gas
3. issuing regulations regarding the supply of natural gas from and to EU member states and third countries.

Furthermore, as part of EU Regulation 994/2010 Austria has elaborated its risk assessment, for which it scored 178.8% for compliance with the N-1 standard. It is currently completing its Preventive Action Plan and Emergency Plan.

Austria does not have government stocks, nor does it place an obligation on its suppliers to hold natural gas reserves.

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Belgium

Key data

Table 4.3.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Demand (kb/d)	335.7	362.0	359.6	335.9	324.1	310.8	286.7
Motor gasoline	96.4	91.8	94.0	79.0	73.3	66.1	-
Gas/diesel oil	107.3	111.0	102.3	106.8	114.9	113.5	-
Residual fuel oil	49.6	55.6	57.5	55.0	43.0	39.3	-
Others	82.3	103.6	105.7	95.0	93.0	92.0	-
Net imports (kb/d)	335.7	362.0	359.6	335.9	324.1	310.8	286.7
Import dependency (%)	100	100	100	100	100	100	100
Refining capacity (kb/d)	428.0	427.0	434.0	442.7	442.7	442.7	-
Oil in TPES (%)**	30	29	27	27	28	26	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.3.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	0	0	0	0	0	0	0
Demand (mcm/y)	616	805	820	1 564	1 303	1 130	1 302
Transformation	235	297	255	818	544	0	-
Industry	287	344	375	481	486	0	-
Residential	39	86	51	85	78	0	-
Others	55	78	139	180	195	0	-
Net imports (mcm/y)	616	805	820	1 564	1 303	1 130	1 302
Import dependency (%)	100	100	100	100	100	100	100
Natural gas in TPES (%)	1	2	2	3	2	2	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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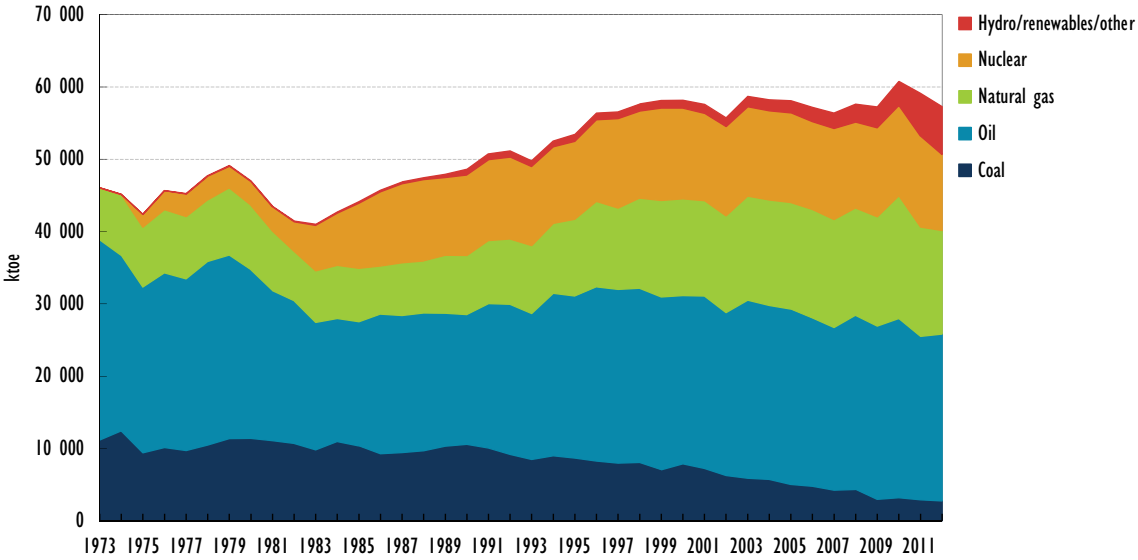
Figure 4.3.1 Total primary energy source (TPES) trend, 1973-2012



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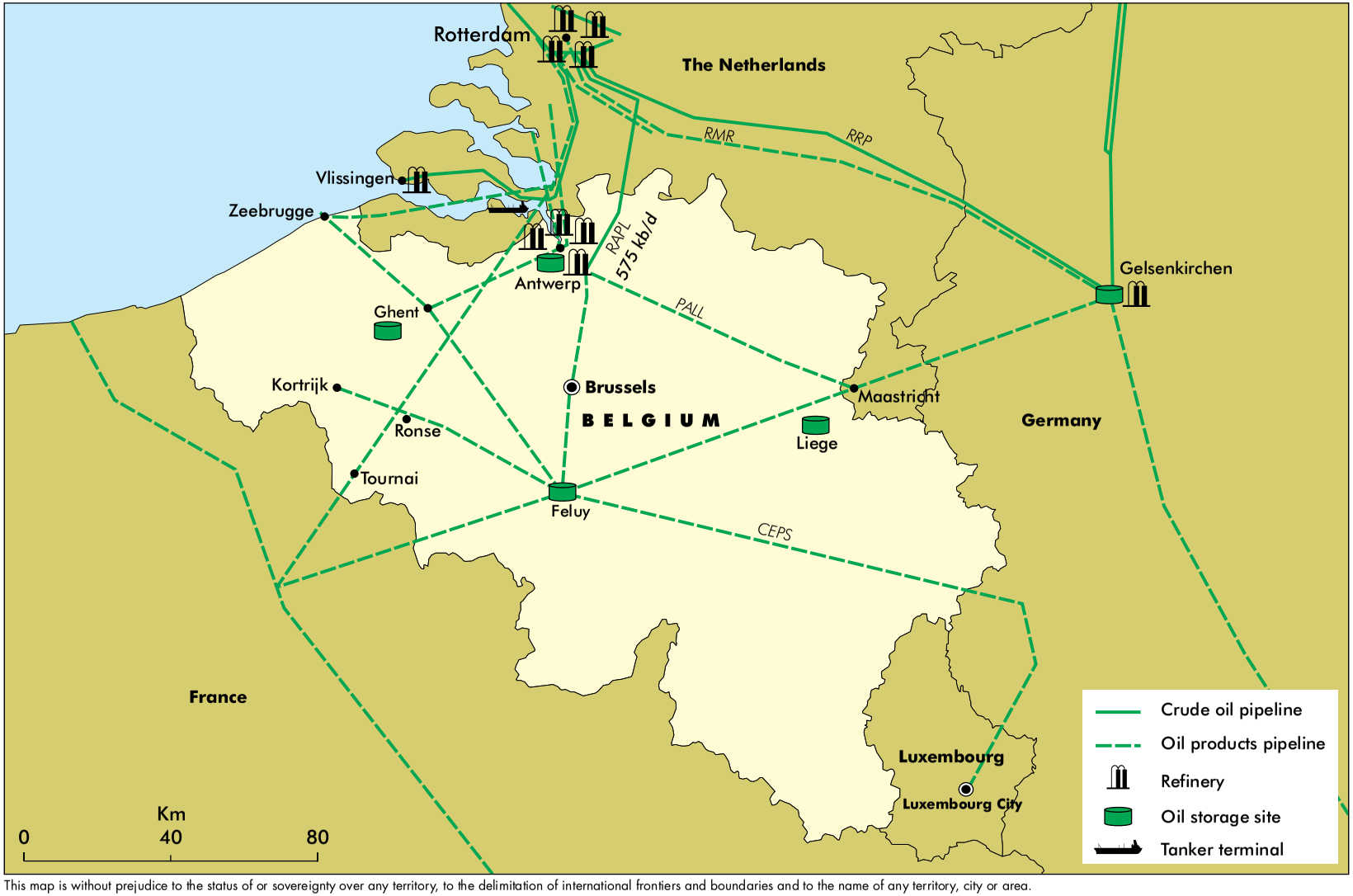
Map 4.3.1 Oil infrastructure of Belgium



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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Map 4.3.2 Gas infrastructure of Belgium

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Country overview

Oil and natural gas provide two-thirds of Belgium's primary energy supply. While total energy use in Belgium is expected to decline slightly in the coming decades, natural gas demand will increase as new power generation capacity to replace ageing power facilities will be mainly gas-fired by 2020.

With no domestic oil or natural gas production, Belgium is fully dependent on imports. Yet, because of its geographical location and infrastructure, Belgium plays an important role in Europe's oil and gas supply chain. In the case of natural gas, Belgium is a major hub of gas flows in the region, with some 80 billion cubic metres (bcm) transiting the country each year, compared to domestic consumption of 18 bcm/year (2012). Oil demand in Belgium is dominated by middle distillates, which represent 44% of the oil products consumed in the country (2012).

Belgium's primary response measure in an oil supply disruption is the use of public oil stocks. Belgium's public stockholding agency, *Agence de Pétrole – Petroleum Agentschap* (APETRA), began operations in 2007. Until its creation, Belgium relied entirely on its domestic oil industry to meet its International Energy Agency (IEA) stockholding obligation. This was done by placing a minimum stockholding obligation on oil importers based on EU regulations regarding the three main product categories. With the creation of APETRA, the obligation on industry was reduced from covering the full stockholding obligation to only 15 days for an initial 5 years, with an annual reduction of three days until 1 April 2012. In April 2012, APETRA became fully responsible for meeting Belgium's national stockholding obligations.

The country has a robust transport network for natural gas that is well integrated with that of other countries through 18 entry points. However, it lacks significant storage capacity. The government relies upon its system operator, Fluxys, to maintain emergency plans for maintaining security of supply.

Oil

Market features and key issues

Domestic oil production

Belgium has no indigenous oil production and is thus 100% dependent on imports.

Oil demand

Demand in Belgium stood at 617.8 kb/d in 2012 and at 622.6 kb/d in 2011, the latest year for which data are available for consumption by sector. In 2011, 45% of total consumption was used in the transportation sector and 32% was consumed by industry. The residential sector, commercial, agriculture and other sectors used 17% of the total, while only 6% was used in the transformation sector for energy generation.

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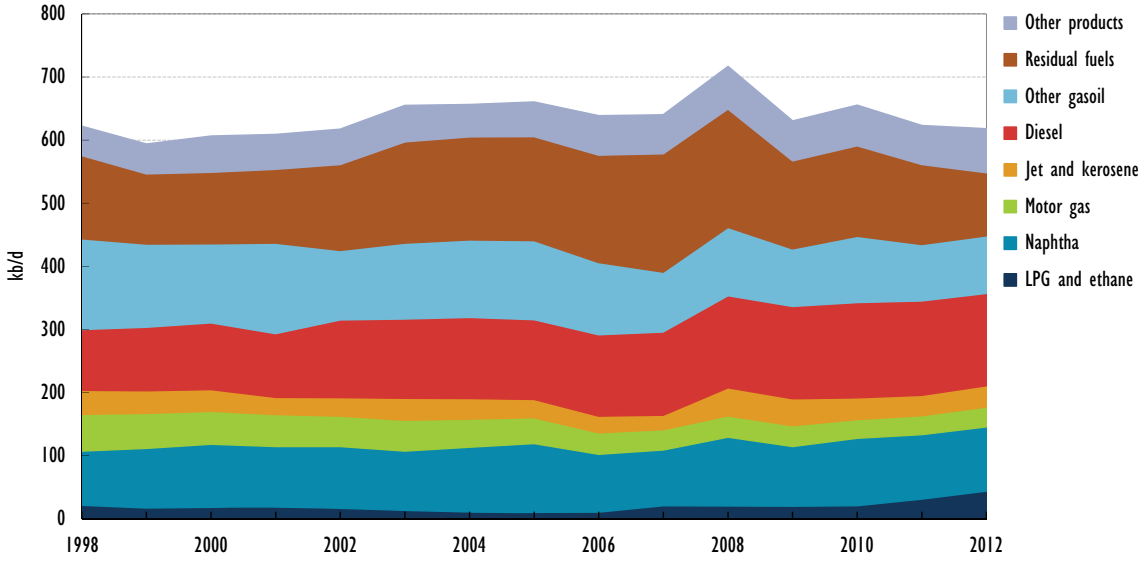
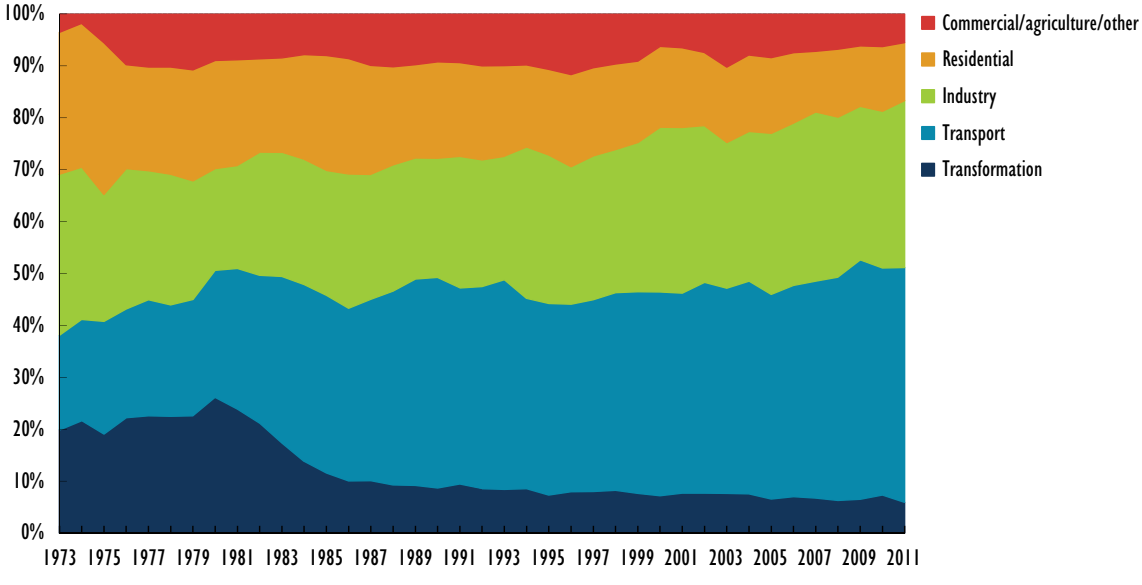
Figure 4.3.2 Oil demand by product, 1998-2012



Residual fuel oil plays a significant role among the energy products used in Belgium (100 kb/d in 2012, but 188 kb/d in the peak years of 2007 and 2008), being overtaken by diesel only in 2009 and by naphtha in 2012. Of the vast majority of the residual fuel oils, 90%, go to international marine bunkers, fuelling international seagoing ships. The remainder is mainly used for industrial purposes and power generation; however, demand is declining because of environmental concerns and greater use of natural gas. Naphtha is also a large component of the country's oil demand (102 kb/d in 2012) as Belgium is one of the main petrochemical hubs in Europe. The use of diesel has been steadily growing in the past years with the exception of 2011 and 2012. In the peak year of 2010, 151 kb/d of diesel was used, with a decline to 147 kb/d in 2012.

Figure 4.3.3 Oil consumption by sector, 1973-2012



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Imports/exports and import dependency

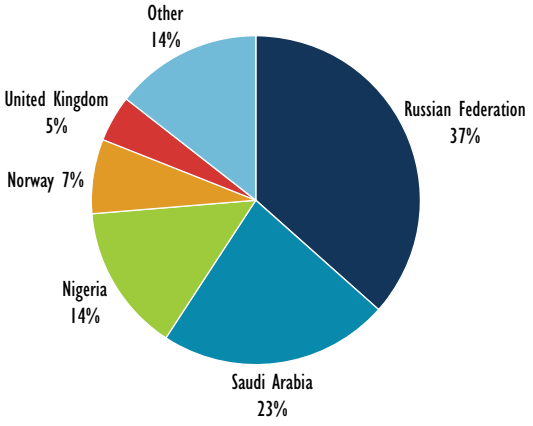
In 2012 crude oil imports came primarily from the Russian Federation (234 kb/d), Saudi Arabia (145 kb/d), Nigeria (93 kb/d) and Norway (47 kb/d). In 2002, Russia rose to be the single most important source of crude oil in Belgium (27% of total) and its importance has continued to grow ever since (37% in 2012).

While fully dependent on crude oil imports, Belgium is an overall net exporter of refined products. Belgian refinery output is traded across much of Europe; Belgian refineries supply two-thirds of Luxembourg's product import requirements and, given their proximity to the Amsterdam/Rotterdam/Antwerp (ARA) barge market and the Rhine and product pipelines, jet kerosene, gas/diesel oil and gasoline are exported to Germany (48 kb/d), France and Switzerland. At the same time, Belgium imports significant quantities of gas/diesel oil from the Netherlands and, to a lesser extent, from Russia. A decade ago, Belgium increasingly became a net importer of fuel oil to meet growing international bunker fuel demand – an increase from 3.3 kb/d in 2002 to a peak 68 kb/d in 2008. Since then, however, the trend has reverted because of the economic crisis and in 2012 Belgium became a net exporter of fuel oil again, with net exports of 4.8 kb/d.

Oil company operations

Four companies operate in the Belgian refining industry: Total, ExxonMobil, Gunvor and Antwerp Terminal and Processing Company (ATPC, VTTi Group). Gunvor replaced Petroplus in 2012 as owner of the Independent Belgian Refinery (IBR), formerly called Belgian Refining Corporation (BRC). Altogether, 20 companies, including majors and independents, import oil, while between 700 and 800 distributors, primarily small companies delivering heating oil, operate on the Belgian market.

Figure 4.3.4 Crude oil imports by origin, 2012



Oil supply infrastructure

Refining

Belgium's four refineries – all located in Antwerp – have a total crude distillation capacity of over 790 kb/d (39 million tonnes per year). The most notable change in refinery activity in recent years is the increase of desulphurisation capacity, which reflects EU specifications to reduce sulphur content for gasoline and diesel, including the move in January 2009 to 10 parts per million (ppm).

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The two major refineries, owned by Total (357 kb/d) and ExxonMobil (298 kb/d), are world class refineries capable of producing a relatively high yield of light and middle distillates. The third, purchased in 2012 by Gunvor from Petroplus, is the smallest and least complex of the three; however, investment in hydro-treating has given it the capacity to produce 10 ppm (parts per million) diesel from a predominantly sour crude slate. The fourth refinery, recenty acquired by the VTTi group, is an asphalt plant with a capacity of approximately 21 kb/d.

In 2012, the country's refined product output totalled 715.2 kb/d and the capacity utilisation rate of Belgium's refineries was 89%. The composition of production was gas/diesel oil (38%), motor gasoline (11%), residual fuel oil (14%) and naphtha (5%). Belgian refineries are able to meet domestic demand for residual fuels, diesel, jet kerosene and gasoline. The production falls short on naphtha, liquefied petroleum gas (LPG) and ethane.

Ports and pipelines

The Port of Antwerp is Belgium's main sea port for oil trade. According to the Antwerp Port Authority, maritime cargo trade of crude oil and products reached nearly 34.6 million metric tonnes (Mt) in 2012. The trade turnover of crude oil shows a significant and steady decrease compared to 2000 levels, when it amounted to 8.1 Mt., dropping to its lowest level since 1985. Trade in products shows the opposite trend, growing from 20.2 Mt in 2000 to 32 Mt in 2012.

The main crude oil pipeline serving Belgium is the Rotterdam-Antwerp pipeline (RAPL), which originates in Rotterdam (the Netherlands) and travels into the Antwerp area. It has a capacity of 575 kb/d.

Apart from inland waterways, a key method for transportation of oil products in Belgium is via the Central European Pipeline System (CEPS). The CEPS is a North Atlantic Treaty Organization (NATO) pipeline network in Europe comprising 6 000 km of pipeline interconnected to roughly 8.2 mb (1.3 mcm) of oil storage capacity. NATO maintains this distribution system primarily to provide fuel supply support to military bases. However, for many years, the pipeline's surplus capacity has been leased for civilian storage, transportation and delivery of oil products. The contracts signed between NATO and the oil companies are based on market prices and supervised by the Ministry of Economic Affairs.

Storage capacity

There are over 40 oil storage facilities in Belgium, with a total combined capacity of just over 12 mcm or 75 million barrels (10.2 million tonnes of crude equivalent). This includes capacity used by industry for normal operations as well as storage capacity used by APETRA for strategic reserves. APETRA is the sole manager of Belgian strategic oil stocks since April 2012, taking over all obligations from industry.

Nearly 1.3 million cubic metres of the capacity are reserved for APETRA, with 380 thousand mcm added in 2012 and another 470 thousand mcm that became operational in 2013. This additional capacity was reached both through expansion of existing facilities and the construction of new facilities.

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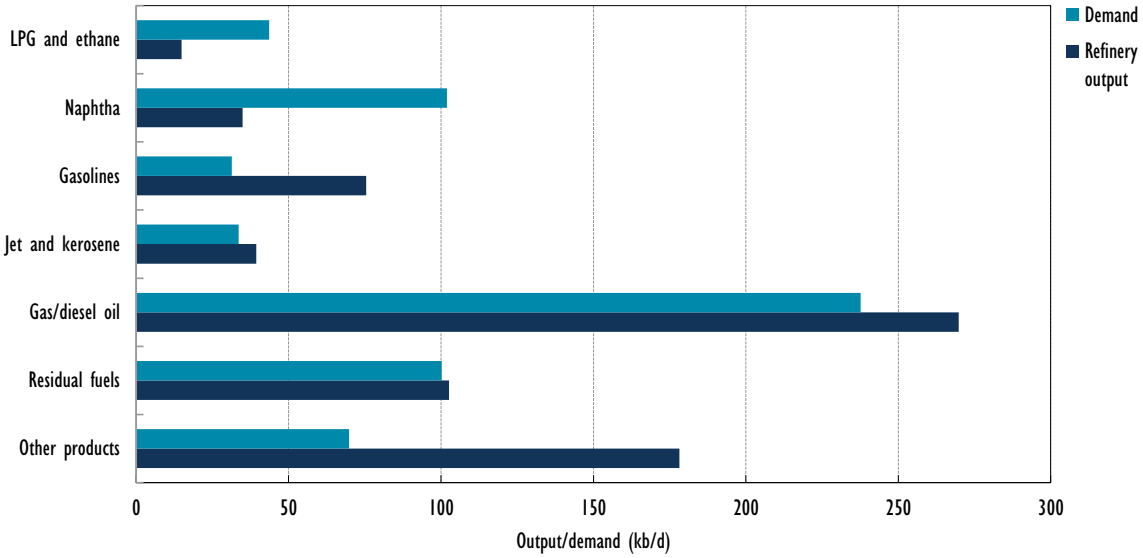
Figure 4.3.5 Refinery output vs. demand, 2012



Decision-making structure

Emergency response policy is the responsibility of the minister in charge of energy, in consultation with the Council of Ministers. Under the Minister for Energy, the General Directorate for Energy, within the framework of the National Oil Board, serves as the core of the national emergency strategy organisation (NESO). This team is responsible for maintaining and implementing emergency response measures in a supply disruption, for monitoring the domestic oil and gas markets and for data collection.

The National Oil Board (NOB) was created by the Royal Decree of 11 October 1984 and is charged with the supply and distribution of oil products in time of crisis. It also serves as Belgium's NESO.

The permanent unit of the NOB is situated within the framework of the General Directorate for Energy. In a crisis, it can be expanded to include experts from the Department of Economic Affairs, other ministerial departments, the oil stockholding agency APETRA and the oil industry. All proposed measures would have to be considered by the Inter-Ministerial Economic Commission (CEI), which represents various government departments. The Minister of Energy would then submit the proposals to the Council of Ministers for final approval.

The NOB's main tasks in case of a supply disruption are to identify vital points (e.g. refineries, pipelines, storage), propose possible crisis measures (e.g. stock, demand restraint) and to determine essential users. The NOB has three stages of operations in a crisis:

- **Monitoring Phase**: to monitor market developments and update information required for the implementation of crisis measures.
- **Active Phase**: to propose measures to the Council of Ministers.
- **Operational Phase**: Implementation of measures and communication with other international bodies, i.e. Benelux, EU, IEA and NATO.

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Stocks

Stockholding structure

Until 2007, Belgium relied entirely on its domestic oil industry to meet its IEA stockholding obligation.

In January 2006 Belgium passed legislation (the Law of 26 January 2006) which created the public stockholding entity APETRA and established a schedule for shifting stockholding responsibilities from industry to the public agency. APETRA's first year of operation began on 1 April 2007. As of this date, the obligation on industry was reduced from covering the full stockholding obligation to only 15 days, gradually being reduced by three days each year until 1 April 2012, at which time APETRA became fully responsible for meeting Belgium's national stockholding obligation.

Crude or products

APETRA may hold its share of compulsory stocks as either refined products or crude oil. The legislation limits the amount of crude oil held by APETRA to 50% of all owned stocks. If APETRA purchases crude oil towards its stock obligation, it must fix both refining yields and refining costs for that crude with a Belgium refinery that will process the crude in the event of an emergency stockdraw.

Location and availability

APETRA may fulfil its stockholding responsibilities through oil stocks it directly owns (purchased by tender) or by obtaining stockholding (ticket) contracts with industry, either domestically or abroad under bilateral agreements.

APETRA stocks may be held by both Belgian and foreign oil companies and retained within their normal operating systems. Up to a maximum of 30% can be kept abroad under bilateral agreements. Belgium has such agreements with France, Germany, Ireland, Luxembourg, the Netherlands and the United Kingdom.

Monitoring and non-compliance

APETRA must inform the Energy Directorate for Energy of the Ministry of Economic Affairs and Energy of the location and composition of their stocks. This information must be reported by the 15th day of each month, describing stocks held at the beginning of that month. The minister may authorise physical checks to ensure full compliance with all the provisions of the legislation. Penalties for infringements range from fines to imprisonment for up to one year.

All of APETRA's operations are subject to direct control by the Ministry of Energy.

Stock drawdown and timeframe

In the event of an oil supply disruption, the Minister of Energy has the legal authority to draw down oil stocks. The minster would direct APETRA to draw down its emergency stocks.

APETRA has put in place agreements with a number of refineries, referred to as the Crude Against Product Agreement (CAPA). In times of crisis, this allows the simultaneous sale of crude oil from APETRA and the purchase of products by APETRA. Within the contract for delivery, products would be delivered within 10 days and not later than 30 days from the time of the crude delivery to the refinery.

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Storage contracts stipulate that the delivery of stocks must begin within 24 hours of a request by APETRA, while the totality of the stocks must be delivered within 30 days.

Ticket contracts with APETRA specify that delivery of finished product must be guaranteed within 30 days (if ticketing on crude oil) and 7 days for tickets on product.

Financing and fees

APETRA's activities are financed through fees levied on all quantities of the relevant products delivered into domestic consumption. Every oil company that pays excise and national taxes on oil products must also pay levy fees to APETRA. The base calculation for the APETRA fees, which has been decided by the government and promulgated by royal decree, reflects several cost factors such as renting or writing off stockholding capacity, renewing the product, the external and internal control of the stocks, and the interest paid on bank loans.

APETRA finances its own purchases of crude/products through bank loans.

Other measures

Demand restraint

Belgium does not have a specific contingency plan to implement demand restraint measures in a disruption, but has at its disposal a number of dormant decrees which the Minister of Energy could activate after deliberation by the Council of Ministers. Possible measures include:

- speed limits
- driving restrictions (e.g. bans on Sundays, pair- or impair number plates) or complete driving ban
- rationing of distribution of fuel oil
- rationing of the distribution of motor oil
- restriction of exportation of certain oil products.

There are no volumetric estimates for each of the separate demand restraint measures, but the total impact of all measures is estimated to be less than 5% of total oil consumption.

The NOB has compiled a crisis management manual that includes updated lists of the priority end-users of petroleum products. These lists serve as a reference for drawing up ministerial decrees regarding demand restraint measures that focus on specific products or consumer groups.

Fuel switching

Fuel switching in Belgium is driven primarily by market prices and is not subject to any legal obligations. The use of oil has been declining in power generation. It accounts for less than 1% of power supply and is expected to be eliminated completely in the near future. Thus, there is little potential for fuel switching in the power sector.

Other

With no domestic crude oil production, surge production is not an available response measure.

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Gas

Market features and key issues

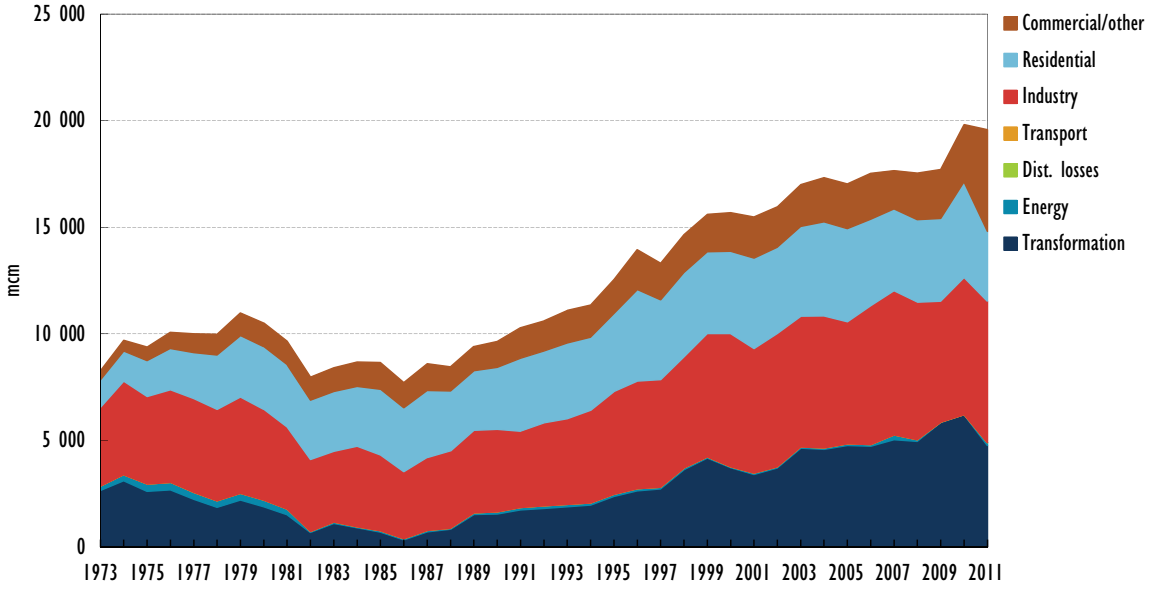
Gas production and reserves

Belgium has no indigenous gas production and therefore relies on imports to supply all its domestic requirements. Its strategic location between the sources of European gas to its north and west, and their primary markets to the south and east, makes the country pivotal for the trade of gas in Europe.

Gas demand

Demand for natural gas was just nearly 18 billion cubic metres (bcm) in 2012. In 2011, industry, primarily related to petrochemical activities, consumed 34% of this amount. Electricity generation made up 25% of gas consumption, and household demand accounted for another 17%.

Figure 4.3.6 Natural gas consumption by sector, 1973-2011



Natural gas is the second main source of fuel for the electricity generated in Belgium (18% in 2011), after nuclear (65% in the same year). Demand for gas in the use of power generation is expected to increase sharply in the coming years. This is caused by the fact that most of the new power generation to replace ageing power facilities by 2020 will be gas-fired.

Gas import dependency

Imports are fairly diversified by origin and type of supply: Norway (36% in 2012) and the Netherlands (26% in 2012), each representing about one-third of total imports, are the principle pipeline suppliers, while Qatar (12% in 2012) is the main source of liquefied natural gas (LNG) imports.

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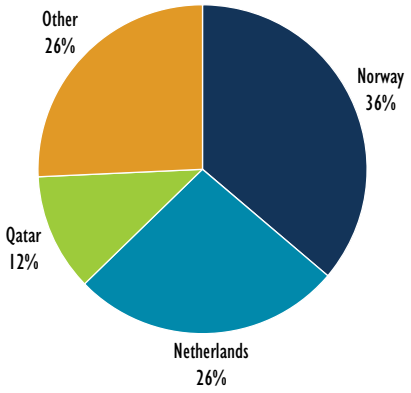
Figure 4.3.7 Natural gas imports by source, 2012



There are two qualities of natural gas in Belgium: H-gas (high calorific) and L-gas (low calorific). H-gas supplies most of the country's demand, but L-gas is used by a quarter of the country's consumers and supplies certain regions exclusively, including Antwerp, Limburg, Flemish Brabant, Walloon Brabant and Hainaut, and Brussels. L-gas is transported from the Dutch Slochteren field on a network that is physically separate from the H-gas network.

Gas company operations

In 2006 Fluxys was appointed by law as the only operator of the natural gas transmission grid and the natural gas storage facility. Fluxys LNG is the sole operator of the LNG facility at the Zeebrugge port. There are 18 suppliers active on the Belgian market (in 2012). However, in 2012, the three most prominent authorisation holders supplied nearly 80% of the market: Eni Gas & Power (41 %), GDF Suez/Electrabel (28%) and EDF Luminus (10%).

The Belgian government has no ownership in the upstream/downstream sectors but still has a golden share of the transmission system operator (Fluxys) and the major supply company (Eni Gas & Power, formerly Distrigas).

Gas supply infrastructure

Ports and pipelines

Fluxys, Belgium's transmission system operator (TSO) has a network of more than 4 000 km of pipelines with 18 interconnection points. This is used both to transport natural gas for consumption in Belgium (17.9 bcm in 2012) and for transit of some 4 bcm of gas to other end-user markets. The Fluxys network delivers gas to power stations and large industrial end-users directly, and supplies the grids of the 18 distribution system operators which deliver gas to residential and small to medium-sized industrial users.

The Zeebrugge port has an LNG regasification facility (operated by Fluxys) with a capacity of 9 bcm per year. At the same time, Zeebrugge serves as a crossroads of two major axes in European natural gas flows, as both the Zeepipe terminal (natural gas coming from Norway) and the interconnector terminal (natural gas coming from or going to the United Kingdom) are situated in the harbour zone. This allows the flow of gas on the east/west axis from Russia to the United Kingdom and the north/south axis from Norway to Southern Europe.

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Zeebrugge also has a key commercial role in the natural gas trade as one of Europe's leading international spot markets for natural gas. More than 78 members are active on the hub and approximately 65 bcm of natural gas was traded on the hub in 2012, equivalent to over 4 times the annual consumption rate for the Belgian market.

The transit of gas through Belgium is via the major two-way, high-pressure pipeline systems connecting Belgium to its neighbours. The VTN-RTR pipeline runs from west to east linking the United Kingdom with Germany. Lines also run from east to south linking the North Sea and the United Kingdom to France and from north to south, linking the Netherlands with France.

Storage

An aquifer in Loenhout (operated by Fluxys) is used to compensate for seasonal swings in purchase contracts and is the only facility exclusively destined for storage. Loenhout's capacity is 725 mcm of H-gas, of which 20 mcm is reserved for Fluxys for balancing of the network; it has a peak output capacity of 15 mcm/day. Short-term storage is available at Zeebrugge.

There is no storage for L-gas in Belgium. The Slochteren field itself is used to compensate for the lack of L-gas storage through the use of flexible, long-term contracts with the Netherlands.

Emergency policy

The federal agency for supplying natural gas (the Agency), under the responsibility of the Minister for Energy, forms a crisis team that is responsible for the co-ordination of emergency planning and communication with various government agencies and supranational institutions. The Agency also works as a liaison body between the TSO (Fluxys), the natural gas companies, government bodies, the European Commission and other EU member states in the event of a natural gas supply disruption.

Fluxys is given the responsibility for maintaining crisis mechanisms through a royal decree on public service obligations related to natural gas (23 October 2002). This includes the requirement to have an emergency plan and backup plan, to be updated every two years. It also includes a code of conduct which contains a range of operational and administrative guidelines for users of the gas network.

Fluxys maintains an emergency plan for ensuring the integrity of its grid (maintaining line pressure and gas quality). In the case of significant loss of gas supply, the TSO looks to balance the network by shifting gas through its various entry points. In doing this, it maintains an "interruption plan" for cutting supply to end-users for short periods of time. Fluxys estimates it is able to compensate for the full loss of gas through its largest entry point for the duration of six hours, during which time the affected shippers should reallocate their supplies through alternative entry points or take other measures to compensate for the loss. In case the shippers are unable to react sufficiently during that period, Fluxys would begin cutting off supplies to specific end-users based on an interruption hierarchy that takes into account safety and alternative sources. This begins with power plants, then industry users.

The federal regulator, *Commission de Régulation de l'Electricité et du Gaz* (CREG), monitors the natural gas market and has powers to approve transportation and distribution tariffs and other regulated assets. Thus, any plans of Fluxys to increase capacity for dealing with supply disruptions would have to be approved by CREG in order to pass on costs through increased tariffs. Regional regulators (*Vlaamse Regering* (VREG) of Flanders, *Commission wallone pour l'Energie*) CWaPE of Wallonia and Brugel for Brussels)

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also have legal powers to monitor the distribution of natural gas and ensure compliance with regional public service obligations.

Emergency response measures

There is no strategic storage of natural gas in Belgium; all gas stocks in Belgium are held by industry for commercial purposes.

According to the EU Regulation 994/2010 (on the security of supply of natural gas), gas distributors must be able to supply protected customers for a 7-day peak period in extreme temperatures, for at least 30 days of exceptionally high demand, as well as for at least 30 days in the case of disruption of the single largest gas infrastructure. Belgium has yet to accommodate for these requirements in national legislation.

There is no demand restraint programme in place in Belgium in order to rapidly reduce gas use in the short term during a gas supply disruption.

There is no programme in place in Belgium to encourage or otherwise require users of gas to switch to other fuel sources in the event of a gas supply disruption.

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Canada

Key data

Table 4.4.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	1 964.7	2 729.3	3 040.9	3 333.0	3 526.7	3 759.8	5 001.9
Demand (kb/d)	1 721.6	2 013.9	2 315.0	2 264.6	2 266.0	2 286.5	2 220.3
Motor gasoline	585.1	659.1	704.0	754.6	762.4	739.4	-
Gas/diesel oil	400.9	489.9	531.9	552.4	565.0	533.7	-
Residual fuel oil	173.2	130.6	194.7	86.6	64.2	59.6	-
Others	562.3	734.4	884.4	871.0	874.3	953.8	-
Net imports (kb/d)	- 243.1	- 715.4	- 725.9	- 1 068.4	- 1 260.7	- 1 473.3	2 781.6
Import dependency (%)	- 14.1	- 35.5	- 31.4	- 47.2	- 55.6	- 64.4	125
Refining capacity (kb/d)	1 852.0	1 911.7	2 017.4	2 103.2	2 103.2	2 103.2	-
Oil in TPES (%)**	37	34	35	34	33	33	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.4.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	109 071	181 673	187 341	159 929	159 715	156 547	154 284
Demand (mcm/y)	67 319	91 537	92 035	95 642	102 421	100 706	106 509
Transformation	3 013	10 790	11 246	15 714	18 068	0	-
Industry	24 920	28 660	26 933	30 960	32 907	0	-
Residential	13 987	16 974	16 884	15 971	17 694	0	-
Others	25 399	35 113	36 972	32 997	33 752	0	-
Net imports (mcm/y)	- 41 752	- 90 136	- 95 306	- 64 287	- 57 294	- 55 841	- 47 775
Import dependency (%)	- 62.0	- 98.5	- 103.6	- 67.2	- 55.9	- 55.4	- 45
Natural gas in TPES (%)	26	29	29	31	33	33	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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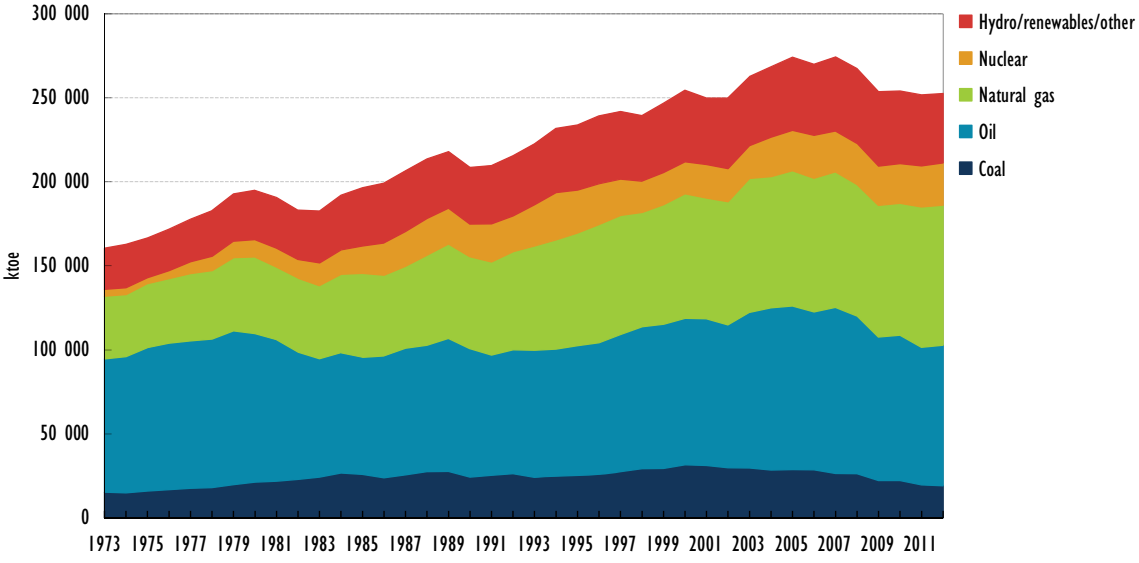
Figure 4.4.1 Total primary energy source (TPES) trend, 1973-2012



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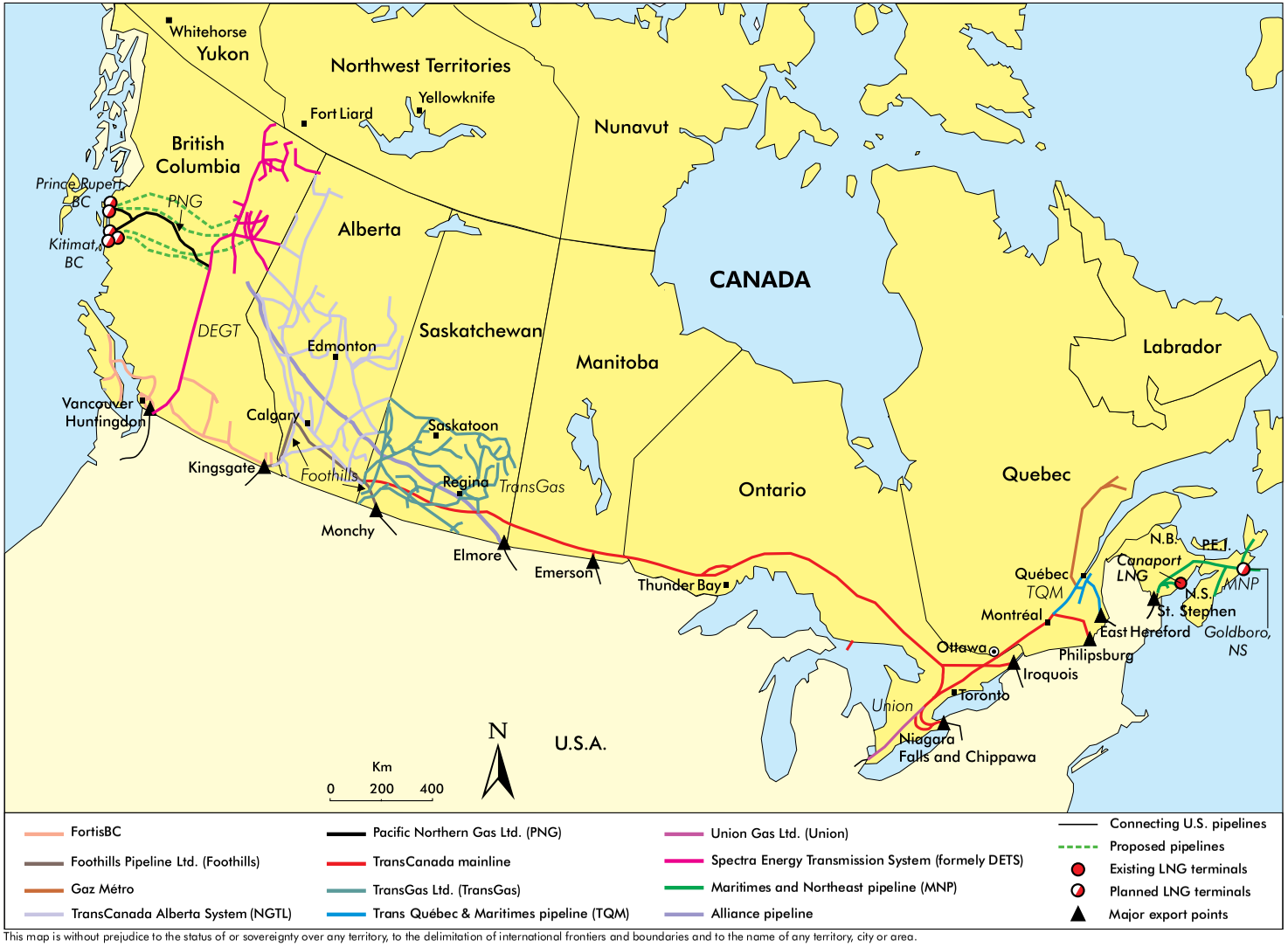
Map 4.4.1 Oil infrastructure of Canada

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Map 4.4.2 Gas infrastructure of Canada



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Country overview

Oil and natural gas are the dominant energy sources in Canada, each accounting for 33% of the country's total primary energy supply (TPES) in 2012.

Canada is a significant net oil and natural gas exporter, and the country's indigenous oil production is continuing to increase. Since 1999, oil production has consistently been rising, as new oil sands and offshore production have more than replaced declining production from ageing fields.

In 2012, Canada's total oil production averaged 3.8 million barrels per day (mb/d). Conventional crude oil accounted for 2.2 mb/d of this production, and unconventional oil sand crudes for another 0.9%. Conventional crude oil production increased by 16% from 2010 to 2012, and unconventional oil sands crudes by around 13% during the same period.

Almost 40% of the oil produced domestically in Canada is exported – with net exports averaging 1.47 mb/d in 2012. Most of these exports go to the United States, with Canadian crude oil accounting for around 28% of total US crude imports in 2012.

Total Canadian oil resources are estimated at approximately 172 billion barrels, making Canada the world's third largest resource holder after Saudi Arabia and Venezuela. Some 98% of this oil is located in the Alberta oil sands.

At the same time, Canada is not immune to the risks of a supply disruption. Despite increases in nearby offshore production, refiners in the country's eastern provinces rely on imported crude oil, just as many refiners in other IEA countries do, and certain central provinces have experienced oil product disruptions, owing to their relative geographic isolation from alternative sources of supply. Moreover, with an extensive system of pipelines moving large volumes of oil from the west towards domestic and US markets across the continent, a significant disruption to any of these pipelines could pose a serious challenge to domestic oil supplies.

Although a major producer and exporter of natural gas, Canadian natural gas production is slowly declining. The country's domestic production stood at 156.5 bcm in 2012, down from 187 bcm in 2005. Production levels are expected to continue to slowly decrease in coming years, reaching 154 bcm in 2018.

Despite the decline, Canadian domestic production still exceeds domestic demand by around 55%. Domestic demand for gas in 2012 stood at around 100 billion cubic metres (bcm), leaving 56 bcm available for export that year. As of the end of 2012, all this surplus production is exported to the United States, but there is the possibility that Canada may start exporting liquefied natural gas (LNG) further afield as early as 2015.

The natural gas market in Canada – and in North America as a whole – is resource-rich, efficient, vast, competitive and diversified. In combination, these market characteristics make a strong, positive contribution to Canada's natural gas supply security.

Oil

Market features and key issues

Domestic oil production

In 2012, Canada's total oil production averaged 3.8 mb/d. Conventional crude oil (light, medium, heavy and offshore oil) accounted for about 2.2 mb/d of the

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country's production, natural gas liquids (NGLs) accounted for a further 0.6 mb/d, and unconventional oil sands crudes (bitumen blend, synthetic bitumen blend and upgraded oil sands light) accounted for 0.9 mb/d.

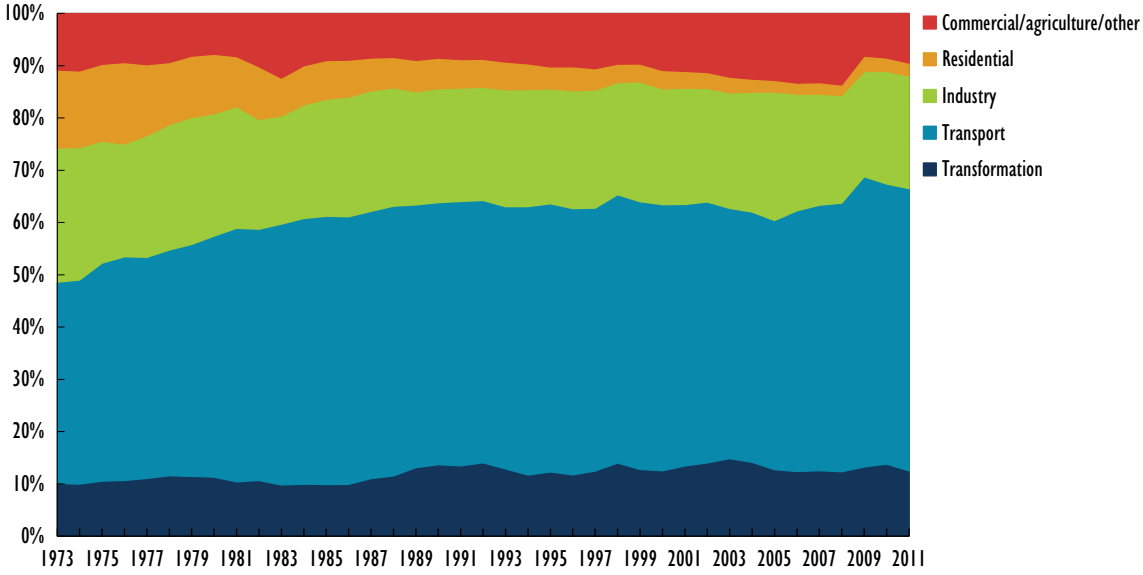
All three categories of oil production are increasing (and have been increasing since 1999), with crude oil up by almost 16% from 2010 to 2012, NGLs up by 2.3% from 2010 to 2012, and unconventional oil sands crudes up by more than 13% during the same period. According to International Energy Agency (IEA) figures, Canadian total oil production will continue to increase rapidly, and is estimated to reach more than 5 mb/d by 2018.

Oil demand

Total oil demand in Canada has been relatively flat in recent years, averaging 2.29 mb/d in 2012, up slightly from 2.27 mb/d in 2011. Canadian oil demand is expected to remain flat, or decline, in the medium term – with a decline to 2.22 mb/d forecast for 2018 (according to IEA figures).

The transport sector accounted for some 54% of the country's oil demand in 2011, with industry a distant second at 22%. The transformation sector only accounted for 12% of Canada's oil consumption.

Figure 4.4.2 Oil consumption by sector, 1973-2011



The biggest single source of oil product demand in 2012 was gasoline, which accounted for 32% of total Canadian oil demand in 2012, followed by diesel at 13%, and other gasoil accounting for 12% of total demand.

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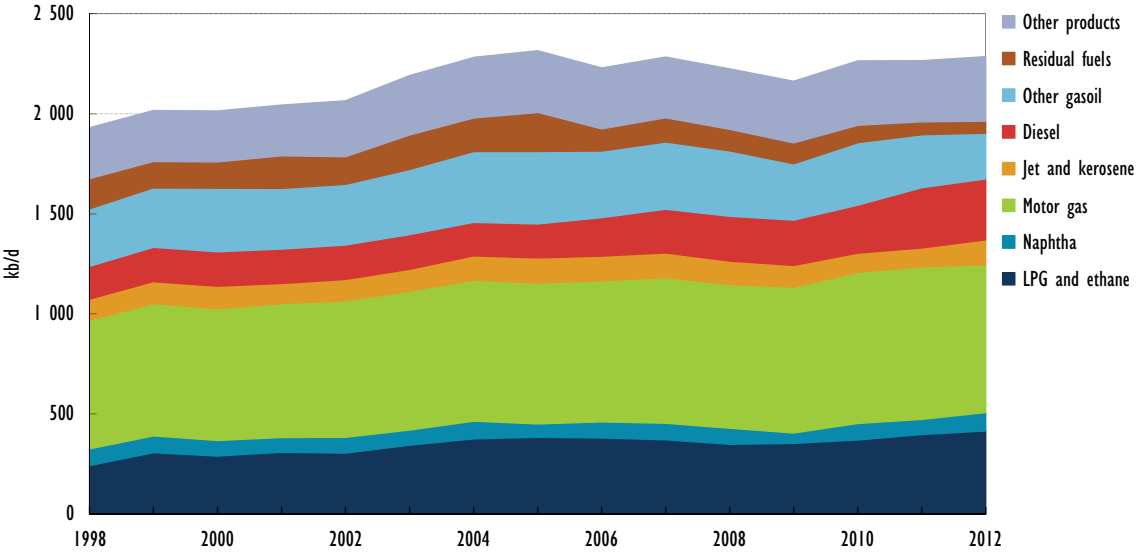
Figure 4.4.3 Oil demand by product, 1998-2012



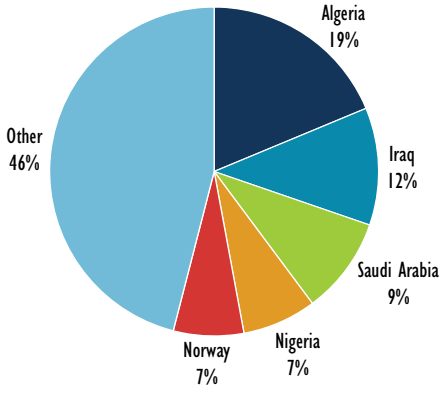
Imports/exports and import dependency

Canada is a large and growing net exporter of crude oil, and is likely to remain so for the foreseeable future. Almost 40% of the oil produced domestically in Canada is exported – with net exports averaging 1.47 mb/d in 2012. These exports are destined almost entirely for the United States. This made Canada the largest single source of crude oil imports for the United States in 2012 – with Canadian oil accounting for around 28% of total US crude imports.

However, despite being a significant net exporter, Canada still imports limited amounts of crude oil (714 kb/d in 2012) to supply some domestic markets. While most of the country's oil exports are produced and shipped from western Canada and the offshore Atlantic east coast oilfields, crude oil is at the same time imported to supply the eastern and central regions. For example, some of the refineries in eastern Canada source their crude oil supplies from overseas (including the United States).

The country's crude oil imports are well diversified, coming from a wide range of countries. The largest single source of imports in 2012 was Algeria which accounted for 19% of the total, followed by Iraq at 12% and Saudi Arabia at 9%.

Figure 4.4.4 Crude oil imports by origin, 2012



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Oil company operations

In August 2009, Suncor merged with Petro-Canada to create Canada's largest upstream oil producer. The newly enlarged company, Suncor, became the second largest refiner of gasoline and oil products, and the fifth largest oil and gas company in North America based on market share.

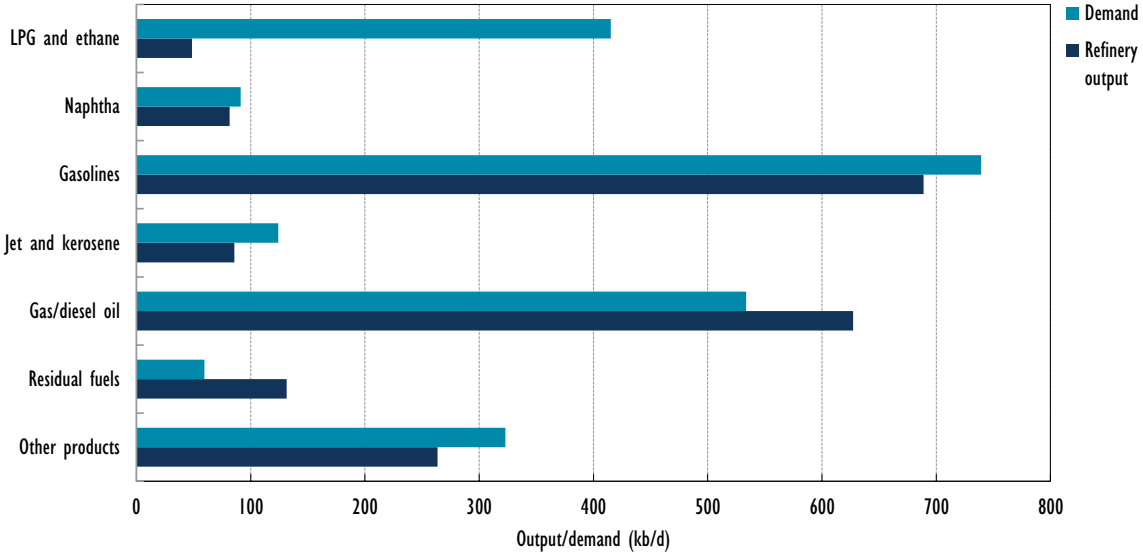
The company is fully privatised as the federal government's last remaining stake was sold in 2005. Many major international oil companies have Canadian affiliates, such as Chevron Canada Resources, Imperial Oil Ltd. (Exxon), Shell Canada Ltd., BP Canada Energy Company, ExxonMobil Canada Ltd. and ConocoPhillips Canada Ltd.

Oil supply infrastructure

Refining

As of the end of 2012 Canada had 15 operational refineries with a total crude oil refining capacity of 1 940 kb/d. Canadian refineries have undergone significant rationalisation over the past three decades, so that the number of refineries has dropped from a high of 40 in the 1970s to the 15 operating in 2012 – with more refinery closures expected. Since the early 1990s, the country's refining capacity has been relatively stable, with utilisation rates averaging around 87% nationally from 2003 to 2012. The country now has two main refining centres: Edmonton, Alberta and Sarnia, Ontario.

Figure 4.4.5 Refinery output vs. demand, 2012



Ports and pipelines

As of the end of 2012, Canada had about 825 000 km of oil transmission and distribution pipelines – of which 71 000 km are federally regulated. (Pipelines are only regulated by the National Energy Board [NEB] if they cross provincial or international borders). The oil produced domestically in western Canada is shipped to domestic and US markets through three main pipeline systems:

- Enbridge Pipeline, which accounts for the bulk of Canadian exports, delivers 2.2 mb/d of oil from Edmonton into Ontario and the US Great Lakes region.

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- Express Pipeline, which delivers crude from Alberta into Wyoming (170 kb/d) and onward into Illinois (120 kb/d) via its Platte Pipeline connection.
- Trans Mountain Pipeline (TMPL), which can transport both crude and products (225 kb/d), delivers oil mainly from Alberta west to Vancouver and the Puget Sound region of the United States.

Canada's oil pipeline capacity is under constant pressure from steadily growing production levels, and there are a number of pipeline companies proposing new infrastructure in Canada.

With regard to port infrastructure, major oil off-loading ports exist in the following cities:

- Quebec
- Saint John, New Brunswick
- Dartmouth, Nova Scotia
- Come By Chance, Newfoundland and Labrador.

Port facilities are also required for oil imports into Canada. As noted earlier, although a major net exporter of oil, Canada imports a significant proportion of the crude oil required for its domestic refineries owing to transport costs and other logistical issues. For this purpose, tankers deliver oil into Newfoundland, Nova Scotia, New Brunswick and part of Quebec.

Storage capacity

Canada does not have publicly held stocks and does not impose a compulsory stockholding obligation on industry. All the country's oil stocks are industry stocks held for commercial purposes. According to IEA figures, the total volume of crude oil and product stocks held by industry in 2012 was 172 million barrels.

Decision-making structure

Both the federal government and the provincial/territorial governments play a major role in Canada's energy policy based on the constitutional division of power between the federal and provincial/territorial governments.

The provinces own all natural resources within their geographic boundaries and are responsible for the conservation, development and management of those resources. The federal government is responsible for matters relating to inter-provincial and international trade, programmes and policies in the national interest (including national economic development and energy security) and resource management on federal lands. The federal government retains control over the resources in the three northern territories, as well as Canada's offshore production. However, because most of Canada's hydrocarbon production and demand occurs within the provinces, the federal government's formulation of energy policies is closely tied to those of the provinces.

Under certain circumstances, the federal government has the authority, under the Energy Supplies Emergency Act, to take measures to reallocate energy supplies within Canada. These circumstances include the declaration of a national emergency, and an IEA collective action under the provisions of the International Energy Program (IEP).

The Energy Supplies Emergency Act provides the authority for the Energy Supplies Allocation Board (ESAB) – a key agency in the event of an oil supply disruption. During periods of business as usual, the Oil Sands and Energy Security Division of Natural Resources Canada serves as the national emergency strategy organisation (NESO).

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However, in an emergency situation, when enabling legislation is activated, there is a much larger emergency organisation that is mobilised under the ESAB.

This ESAB-led group comprises a chairperson and five members. The chair is appointed by the Governor in Council and reports to the Minister of Natural Resources Canada. The board is supported by the Oil Sands and Energy Security Division of Natural Resources Canada and includes personnel from oil companies (in the form of the Petroleum Industry Advisory Committee), transportation organisations, other federal government departments and the provinces (in the provincial advisory committee). The use of the federal government's emergency powers requires provincial consultation before taking emergency action to address some form of market failure.

Stocks

Stockholding structure

As a net exporter, Canada does not have an IEA 90-day stockholding obligation. Canada also does not hold any bilateral stocks for other IEA member countries. All stocks held in Canada are owned by industry. As oil companies are not required to hold emergency stocks in normal times, they maintain stocks for operational and logistical purposes only.

In a declared national emergency, the ESAB would have the authority to regulate company stocks and to penalise companies for violation of its orders under Section 41 of the Energy Supplies Emergency (ESE) Act 1985. Under the ESE Act (Sec. 25 (d)), the ESAB has the authority to regulate the building, storage and disposal of stocks, including industry stocks, during a declared national emergency. The threshold level for triggering the regulation would be decided by the government in consultation with the oil industry on a case-by-case basis. The mechanism requires monthly reports to the ESAB by each company on its stock situation. As the government's emergency policy emphasises market mechanisms and would only use allocation actions as measures of last resort, it is unlikely that commercial stocks would be directed in such a manner.

Crude or products

As of April 2013, total stocks held by industry were made up of around 65% crude, NGL and feedstocks, and 35% finished products.

Location and availability

Industry holds storage facilities along the supply chain for normal operations. Industry stock levels are relatively stable in terms of demand coverage. On average, product inventories provide about 20 to 30 days of forward demand cover, and crude oil inventories have been in the range of 70 to 100 days.

Stock drawdown and timeframe

In the event of a declared national emergency, a drawdown of industry stocks could be carried out by oil companies under the mandatory allocation programme. Initial data submissions would be received by the NESO, and, after consultation with industry via the government's existing advisory committee, a decision would be taken (including an agreement upon the level of stockdraw required and confirmation of the timing) and a stock drawdown would be initiated. Stocks would be released into the market by companies meeting their crude oil entitlement and the product entitlements of their customers. The ESAB has the power to establish parameters for prices, as well as set prices, if necessary, at the time of emergency. This sequence of events would require

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about two to three weeks. The Canadian government indicated that the procedure has been tested on several occasions on paper, but never in a physical situation.

Financing and fees

There are no stockholding obligations on the oil industry in Canada; all oil stocks are held by market operators for normal commercial purposes. Oil companies recoup the costs of stockholding through their normal operations and consumer pricing.

Other measures

Demand restraint

The specific procedures for demand restraint in Canada are described in the ESE Act. Additionally, the Emergencies Act, established in 1988, provides a more flexible approach to demand restraint, allowing Cabinet to authorise the "requisition, use or disposal" of energy commodities. In order to activate either of these legal instruments, Cabinet must first declare an energy-related national emergency.

Theoretically, in an IEA-declared emergency, demand could be restrained by federal mandate through implementation of the Crude Oil and Products Allocation Program. Further demand restraint measures would be implemented by the provinces and territories to complement actions imposed by the federal government.

During an oil supply disruption, and under a declared national emergency, the ESAB would activate allocation plans to ensure that crude oil and products are distributed fairly and equitably to all citizens.

- The **Crude Oil Allocation Program** apportions available crude oil from offshore and domestic sources to refineries throughout Canada, and can be used to free up crude for export, in the case of a supply obligation in the IEP's emergency sharing system.
- The **Petroleum Products Allocation Program** controls the volume of products that refiners and other major suppliers may sell to wholesale customers. Demand restraint in petroleum products could be achieved through the issue of allocation factors which are designed to limit current sales at the wholesale level in each of three priority categories of historical sales, and the effects would be felt immediately. Progress would be monitored on a monthly basis. The three priorities of use are: (a) health, welfare and security of Canadians (e.g. hospital services, fire and police protection, national defence or public transit); (b) economic stability (e.g. most industrial and commercial activities, including public utilities, postal services, taxis and road maintenance); and (c) discretionary activities related to the maintenance of the standard of living (e.g. supplies of gasoline at service stations and of fuels for heating commercial buildings). It would take up to 60 days after the declaration of an emergency to fully implement the mandatory products allocation and issue product entitlements.
- Rationing of gasoline and diesel fuel through coupons can be implemented as a last resort.

The decision process for activating the programme is described in the ESE Act and would involve recommendations from the Board to the Governor in Council (the Cabinet of the federal government).

In the event of an oil supply disruption, the provinces and territories have the authority to implement demand restraint measures.

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Fuel switching

There are no fuel-switching policies in place in Canada.

Other

Canada's federal government cannot really use surge production as an emergency response measure for three main reasons. First, most domestic oil production is already running at maximum potential for commercial purposes. Second, surge production can only be achieved over a short period of time, as there is risk of damaging wells and reservoirs. Third, the federal government has little control over surge production because most oil resources are under provincial jurisdiction.

Gas

Market features and key issues

Gas production and reserves

Canada is a major producer and exporter of natural gas, with domestic production standing at 156.5 bcm in 2012, down from 187 bcm in 2005. The Western Canada Sedimentary Basin (WCSB) accounts for 99% of domestic production. Alberta accounted for 73% of WCSB production, while British Columbia and Saskatchewan accounted for 23% and 3%, respectively. The remaining 2% of domestic supply is produced in Atlantic Canada, the majority from offshore sources, but a small amount of natural gas is also produced in the north of the country.

Natural gas production levels are expected to slowly decrease in coming years, with production forecast to decline to 154 bcm in 2018 according to IEA figures. Despite the decline, Canadian domestic production still exceeds domestic demand by around 55 %. All this surplus production is currently exported to the United States, but there is a possibility that Canada may start exporting LNG abroad as early as 2015.

It should be noted that under the Canadian constitutional framework, provincial governments have jurisdiction over the upstream (exploration and production), and the downstream natural gas markets (distribution). The federal government mainly has jurisdiction over international and inter-provincial trade and pipelines.

Gas demand

From 1990 to 2012, demand for natural gas increased by 49%, from 67.3 bcm to just over 100 bcm.

There is a broad range of demand sources for natural gas in Canada. The largest of these is the industry sector which accounted for 32% of gas demand in 2011, followed by the transformation sector at 18% and the residential sector at 17%. Natural gas is widely used for residential and commercial heating, particularly in the winter months.

Another significant source of natural gas demand in Canada is the (non-transformation) energy sector – especially with regard to oil sands production. The domestic Canadian energy sector accounted for 16% of natural gas demand in 2011.

Despite a progressive increase in demand for natural gas for transformation purposes (from 9% in 1974 to 18% in 2011), natural gas is not a principle source of fuel for the electricity generated in Canada.

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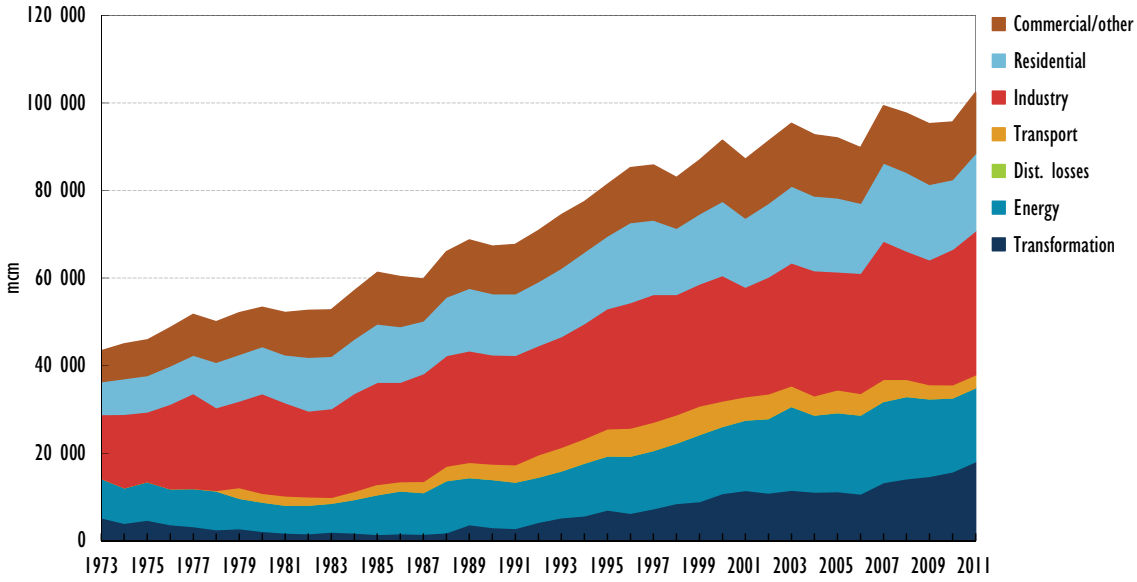
Figure 4.4.6 Natural gas consumption by sector, 1973-2011



Gas import dependency

Canada's net natural gas exports in 2012 totalled around 56 bcm. However, despite the country's status as a significant net exporter of natural gas, there are some import points in Canada located in southern Ontario, where it is typically cheaper to import gas from the US than to ship gas from western Canada through northern Ontario. According to IEA figures, Canada imported just over 31 bcm of natural gas in 2012, while at the same time the country exported around 87 bcm of natural gas – all to the United States.

Gas company operations

Canada has a highly competitive natural gas industry, with hundreds of exploration and production firms operating in the country and no firm having a large enough market share to set prices. According to figures supplied by the government, in 2012 the top 20 producers accounted for some 71% of total production, and the top 100 producers for approximately 87% of total production.

Canada's natural gas gathering, transmission and distribution pipeline network is predominantly owned and operated by publicly traded companies. There are, however, a few transmission and distribution pipelines that are owned by Provincial Crown Corporations, such as SaskEnergy in Saskatchewan, and Manitoba Hydro in Manitoba.

Storage facilities in the producing region of western Canada are typically owned by pipeline companies or producers, while in eastern Canada, storage facilities are typically owned by local distribution companies. Distribution is handled by private companies which have exclusive rights to distribute gas in a given regional or local area, and are provincially regulated.

Gas supply infrastructure

Ports and pipelines

Canada became an LNG importer in June 2009 when the Canaport terminal in Saint John, New Brunswick came on line. Canaport is designed as an import terminal for gas

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that is then re-exported by pipeline to feed growing Northeast US markets. There is no domestic need for the gas imported through Canaport as natural gas demand in Atlantic Canada is fully met by offshore Nova Scotia production.

Because of the significant gas production in Canada, there is an extensive network of gas pipelines throughout the country. The natural gas network in Canada is very well integrated with that of the United States. According to the Canadian Energy Pipeline Association (CEPA), the total length of the natural gas transmission and distribution pipeline network in Canada is about 550 000 km (as of the end of 2012). Around 100 000 km of the network is made up of transmission pipelines, and 450 000 km of distribution pipelines.

Storage

Canada has significant natural gas storage infrastructure that is usually used for servicing peak winter demand. The country has approximately 23.4 bcm of domestic storage capacity (equivalent to about 23% of annual demand) and also has access to an additional 85 bcm of storage in the United States. These storage volumes can be drawn down on very short notice to help satisfy demand or to help address a supply shortfall.

Emergency policy

Canada's federal government has considerable powers to control natural gas flows in a declared national emergency under the Emergencies Act. However, if a national emergency is not declared, then natural gas flows fall under provincial jurisdiction.

Canadian natural gas emergency response policy is generally geared towards short-term rather than long-term supply disruptions. The reason for this is that the government considers that long-term risk is not particularly relevant for North America, as the North American natural gas market is resource-rich and is an open, well-interconnected, competitive commodity market.

Emergency response measures

In the case of a natural gas supply disruption, Canada has a number of options for continuing to meet natural gas demand.

- The country has significant natural gas storage infrastructure that is usually used for servicing peak winter demand. These storage volumes can be drawn down on very short notice to help satisfy demand or to help address a supply shortfall. Canada does not possess strategic gas stocks, and there are no government-imposed requirements for any market participant to hold any minimum level of stocks.
- Although a net exporter of natural gas, Canada also has the facilities to import gas. In the event of a gas supply disruption, Canada could import additional natural gas via pipelines from the United States. In the event of a prolonged disruption, Canada could also bid on spot LNG cargoes, to be received at the Canaport terminal.
- Many industrial natural gas consumers are on "interruptible" service contracts, with the consequence that their natural gas supplies can be diverted elsewhere if required. Shedding demand through interruptible service clients would help in the case of a supply disruption.
- A reduction in natural gas export volumes may also be an option in some emergency scenarios. The North American Free Trade Agreement (NAFTA) prohibits the Government of Canada from imposing any export volume restrictions except under certain circumstances. These exceptions include: the relief of a critical shortage of natural gas;

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domestic price stabilisation; the acquisition of products in short supply; and conservation measures in relation to restrictions on domestic production or consumption. However, any export restriction would invoke the proportionality clause, which provides that the restriction must not reduce the proportion of Canadian production offered to export customers below the percentage of Canadian production exported over the previous 36 months. It is important to note that in the case of an IEA emergency, Canada's IEA obligations supersede any NAFTA restrictions.

- While it may be possible for some electricity generators to switch to different fuels, in a scenario where natural gas is unavailable a natural gas supply disruption would more likely be handled by using other forms of power generation to meet demand. Canada is not heavily reliant on natural gas for electricity supply, and it is likely that other supply options would be sufficient to maintain reliability.
- Fuel switching exists in some industrial facilities with the alternative fuel represented by oil, coal and wood. The reason for fuel switching for natural gas consumers is the fuel price. Given that the Canadian/US natural gas market is flexible, well-functioning, and reliable, there are no requirements to maintain specific stocks of alternative fuels. For electricity generation, there are no requirements to maintain stocks of alternative fuels at the provincial level, or at the federal level, as electricity supply falls under provincial jurisdiction.

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The Czech Republic

Key data

Table 4.5.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	0.0	7.5	11.6	5.9	7.8	6.8	5.5
Demand (kb/d)	184.1	169.8	212.9	201.4	196.9	195.5	201.4
Motor gasoline	26.9	42.9	47.6	43.0	41.5	38.7	-
Gas/diesel oil	68.9	57.6	78.7	83.2	84.8	85.7	-
Residual fuel oil	41.8	16.2	9.5	4.2	3.0	2.0	-
Others	46.5	53.1	77.1	71.0	67.6	69.2	-
Net imports (kb/d)	184.1	162.3	201.3	195.5	189.1	188.7	195.8
Import dependency (%)	100	95.6	94.6	97.1	96.0	96.5	97
Refining capacity (kb/d)	0.0	186.1	198.0	198.0	198.0	198.0	-
Oil in TPES (%)**	18	18	21	20	20	20	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.5.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	262	219	201	203	184	200	146
Demand (mcm/y)	6 573	9 236	9 493	9 280	8 413	8 323	8 920
Transformation	1 259	1 533	1 603	1 251	1 211	0	-
Industry	3 027	3 206	2 984	2 916	2 694	0	-
Residential	1 149	2 524	2 839	2 906	2 441	0	-
Others	1 138	1 973	2 067	2 207	2 067	0	-
Net imports (mcm/y)	6 311	9 017	9 292	9 077	8 229	8 123	8 774
Import dependency (%)	96.0	97.6	97.9	97.8	97.8	97.6	98
Natural gas in TPES (%)	11	18	17	17	17	16	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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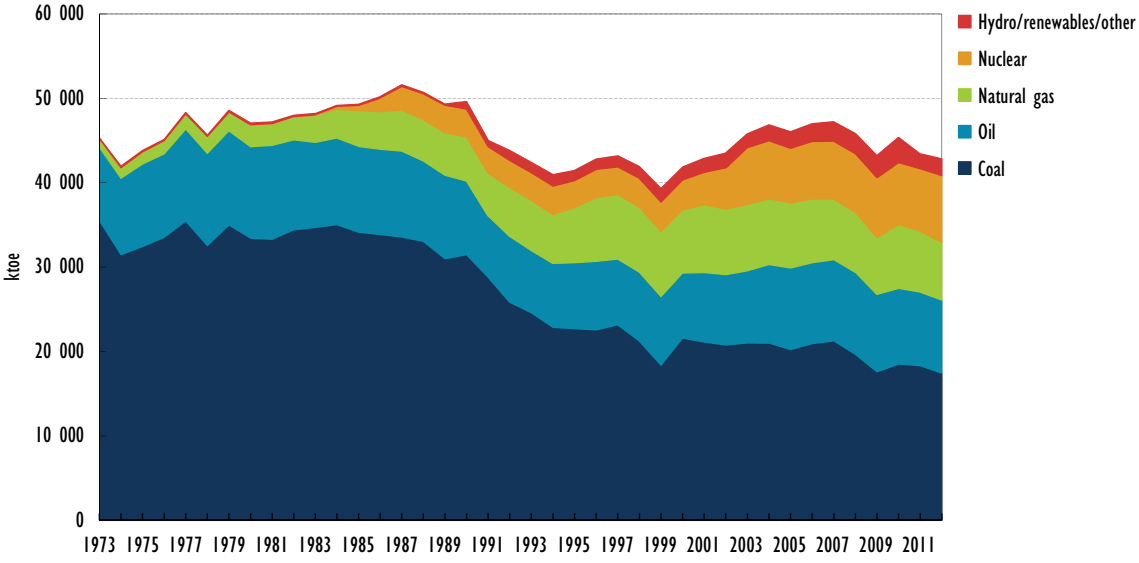
Figure 4.5.1 Total primary energy source (TPES) trend, 1973-2012



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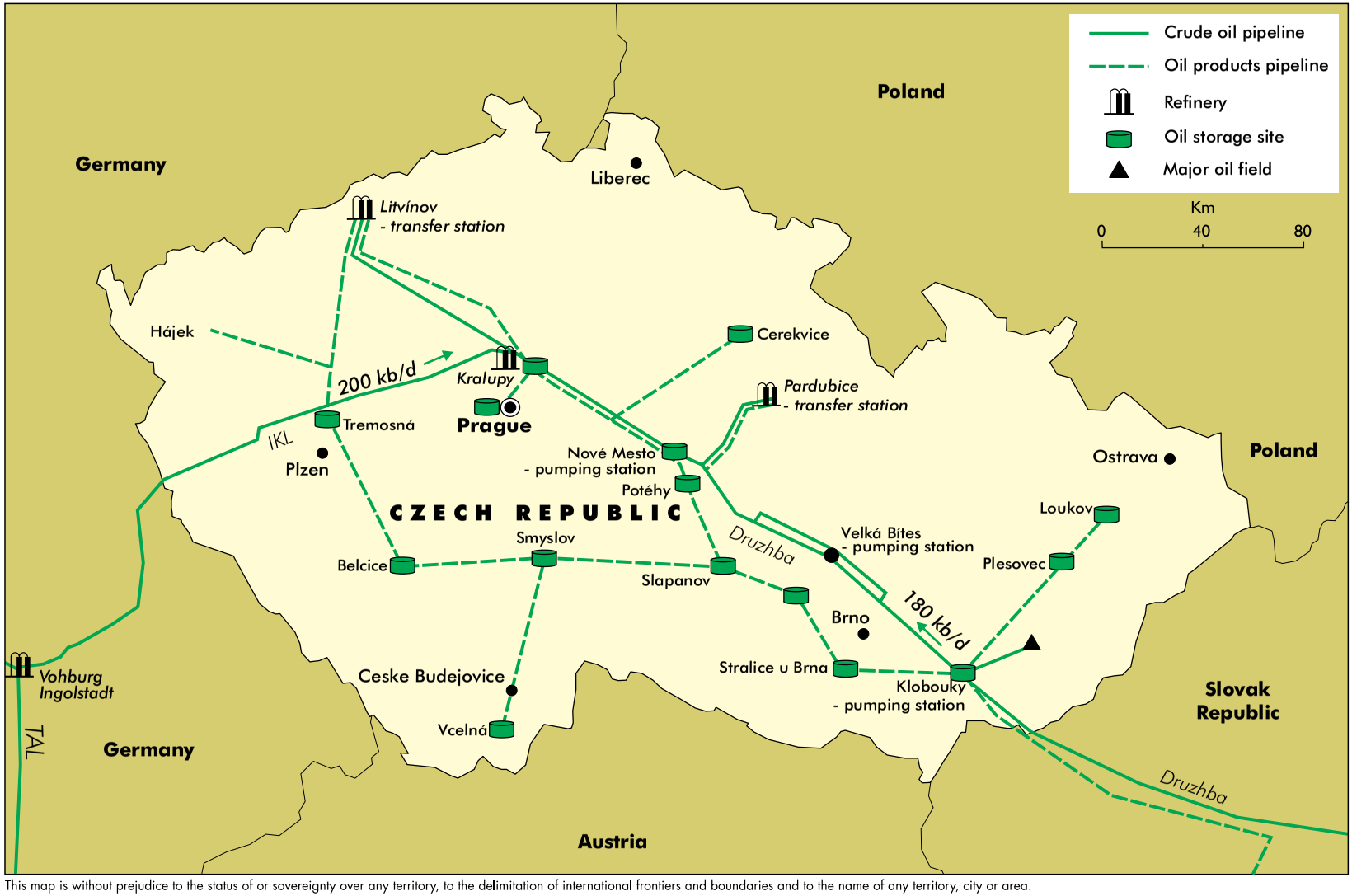
Map 4.5.1 Oil infrastructure of Czech Republic



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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Map 4.5.2 Gas infrastructure of Czech Republic

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Country overview

In 2012, oil represented 20% of the Czech Republic's total primary energy supply (TPES) and natural gas 16%, while coal accounted for the largest share of TPES at 39%. Over the next two decades, the country aims to reduce its reliance on coal, while at the same time maintaining its status as a net exporter of electricity by increasing use of nuclear and renewable energy. Nevertheless, natural gas will have a growing role in the country's future supply mix, and unlike oil, demand for gas will continue to rise in the coming years.

Over 96% of oil demand is met by imports, largely in the form of crude oil from countries of the former Soviet Union (FSU), particularly the Russian Federation and Azerbaijan. Roughly two-thirds of this is delivered through the Druzhba pipeline, a supply line that has experienced interruptions and reduced flows in recent years. Natural gas supplies are equally dependent on imports, and over three-quarters of the 8.3 billion cubic metres (bcm) in gas demand (2012) is met by imports from Russia. The Czech Republic also transits some 30 bcm/yr of Russian gas to other markets further west and expansion of storage and pipeline capacities will play an important role in transiting supplies through the Nord Stream pipeline project.

The Czech Republic's primary response measure in an oil supply disruption is the use of public oil stocks. The office which oversees the state's emergency reserves, the Administration of State Material Reserves (ASMR), has the mandate to cover the entire Czech oil stockholding obligation to the European Union. The chairman of the ASMR has the power to draw down public stocks held in excess of this minimum level, without needing to seek government approval. This allows the Czech Republic to respond quickly to an International Energy Agency (IEA) action or to provide loans to relieve shortages in domestic supplies.

The country benefits from having a relatively high capacity of underground commercial gas storage. However, it does not have strategic reserves or fuel-switching potential for responding to a gas crisis. Following the January 2009 gas crisis in Europe, the Czech government put in place over a short period of time and ahead of the 2009/10 winter season a response plan for dealing with a reduction in gas supplies. This plan relies on co-ordination with industry in order to optimise gas storage use and regulate demand-side measures in a crisis.

Oil

Market features and key issues

Domestic oil production

The Czech Republic does not have significant oil reserves; indigenous production of both crude and natural gas liquids (NGLs), averaging around 7 thousand barrels per day (kb/d), equates to just over 3% of the country's total oil demand. Producing fields are located in the South Moravian Region in the southeast of the country and connected by pipeline to the Kralupy refinery.

In 2012, Czech refineries processed some 7.7 million tonnes (Mt) of crude oil, or roughly 166 kb/d. Crude oil imports in the same year averaged just over 147 kb/d, supplied almost entirely by countries of the FSU. Russia is the single largest source of crude oil imports, providing nearly two-thirds of the total (91.5 kb/d in 2012), while imports from Azerbaijan have steadily grown over the past decade and accounted for 26% of total imports in 2012. The third most important supplier, Kazakhstan, provided 10.5 kb/d, or 8% of total imports in 2012.

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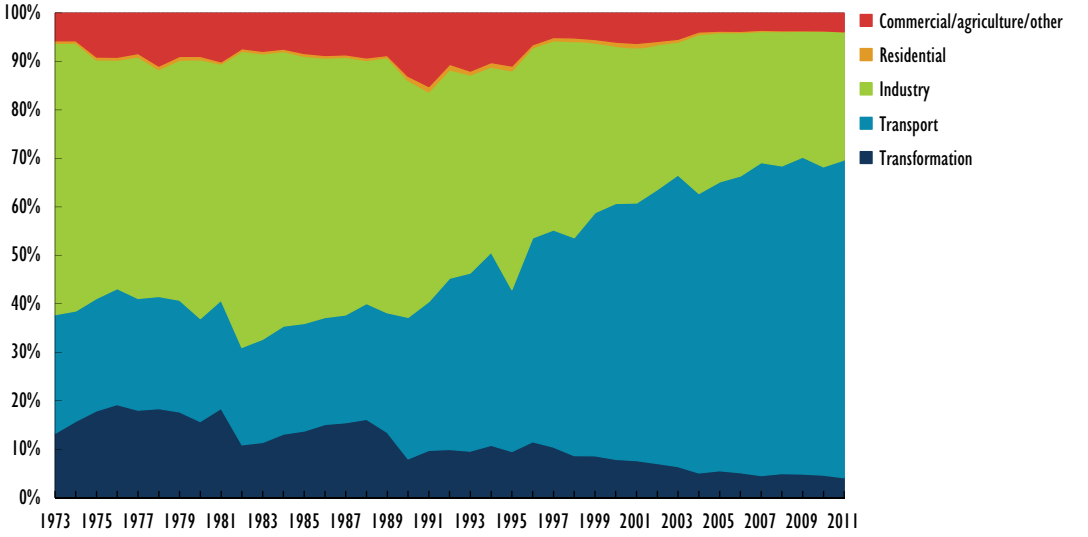
Oil demand

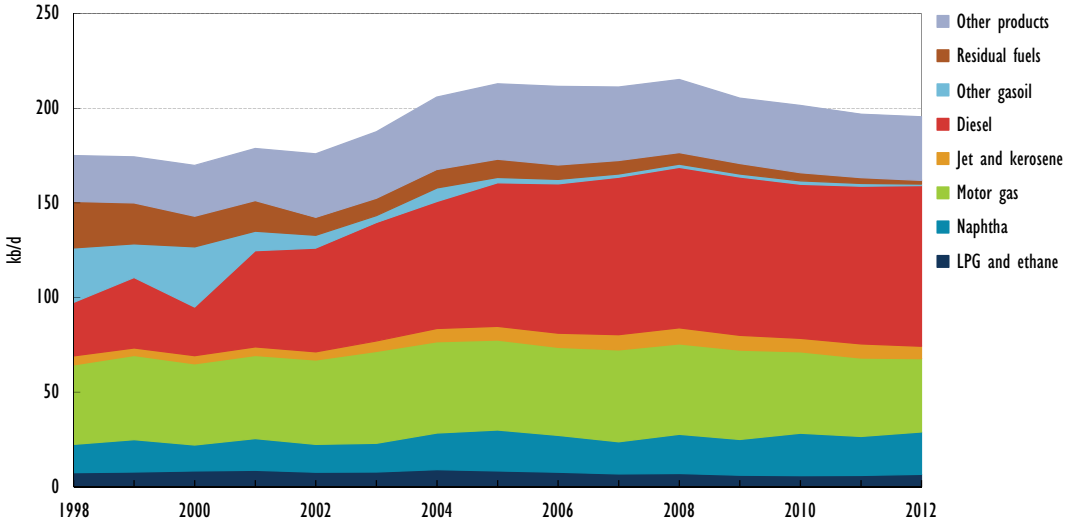
The transport sector accounts for two-thirds of all oil used in the Czech Republic. Diesel is the single largest component in the mix of oil products, representing 43% of total oil demand. Automotive diesel has a price advantage for consumers compared to gasoline owing to a lower tax rate. The accession to the European Union in 2004 is also seen as a significant contributing factor to the increase in diesel demand, as this has led to a greater number of heavy goods vehicles transiting the country.

Figure 4.5.2 Oil consumption by sector, 1973-2011



Oil demand has remained flat since 2005, a year when demand peaked following a period of steady economic growth. Demand for diesel was the driving factor for increased oil demand in the period from 2000 to 2012, when total demand increased at an average annual rate of 4.25%. While total oil demand has slightly decreased since its peak in 2005 (212.9 kb/d), demand for diesel has continued to grow and averaged +11.5% in the period from 2000 to 2012. Oil demand in the Czech Republic is not expected to grow significantly in the coming years.

Figure 4.5.3 Oil demand by product, 1998-2012



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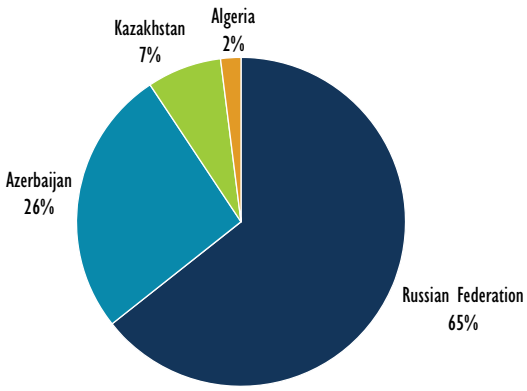
Imports/exports and import dependency

Roughly 97% of the Czech Republic's oil needs are met by imports. Trade in refined products has been almost entirely conducted with neighbouring IEA countries, principally the Slovak Republic and Germany. The Czech Republic imported 61.3 kb/d of refined products and domestically refined 166.2 kb/d in 2012.

Figure 4.5.4 Crude oil imports by origin, 2012



Oil company operations

The company Moravské naftové doly (MND) operates in domestic crude oil production. MND is also involved in natural gas production and the building and operating of underground gas storage facilities.

The state-owned companies MERO and ČEPRO operate the country's crude oil and refined product pipelines and storage terminals, respectively. While financially autonomous, both companies are fully owned by the state.

Two companies operate in the Czech refining industry: Česká rafinérská, which operates the Litvínov and Kralupy refineries, and Paramo, operator of the refinery in Pardubice. Unipetrol, part of the PKN Orlen group since 2004, has full ownership of Paramo and a majority share in Česká rafinérská. The remaining shares in Česká rafinérská are held by Eni (32%) and Shell (16%).

Benzina, also fully owned by Unipetrol, is the largest operator of petrol stations in the country. The other main oil companies operating on the Czech retail and wholesale oil market include Eni/Agip, OMV, Lukoil, Slovnaft, Shell, Total and Tesco stores. ČEPRO also owns and operates a network of 192 petrol stations.

Oil supply infrastructure

Refining

Three refineries in the Czech Republic contribute to a total crude atmospheric distillation capacity of 198 kb/d, or 9.7 million tonnes per year (Mt/year). The two main refineries, Litvínov and Kralupy, account for over 90% of this capacity. The third refinery, Paramo in Pardubice, operates only the lubricants and asphalt units since a reorganisation in 2012. There is a fourth facility located in Kolín, near the Pardubice refinery, which manufactures lubricants but has no atmospheric distillation capacity.

The Kralupy refinery processes sweet crudes (originating from Azerbaijan, Turkmenistan and North Africa, as well as from domestic fields). The Litvínov and Pardubice refineries process the heavier, more sour Russian Export Blend Crude Oil (REBCO).

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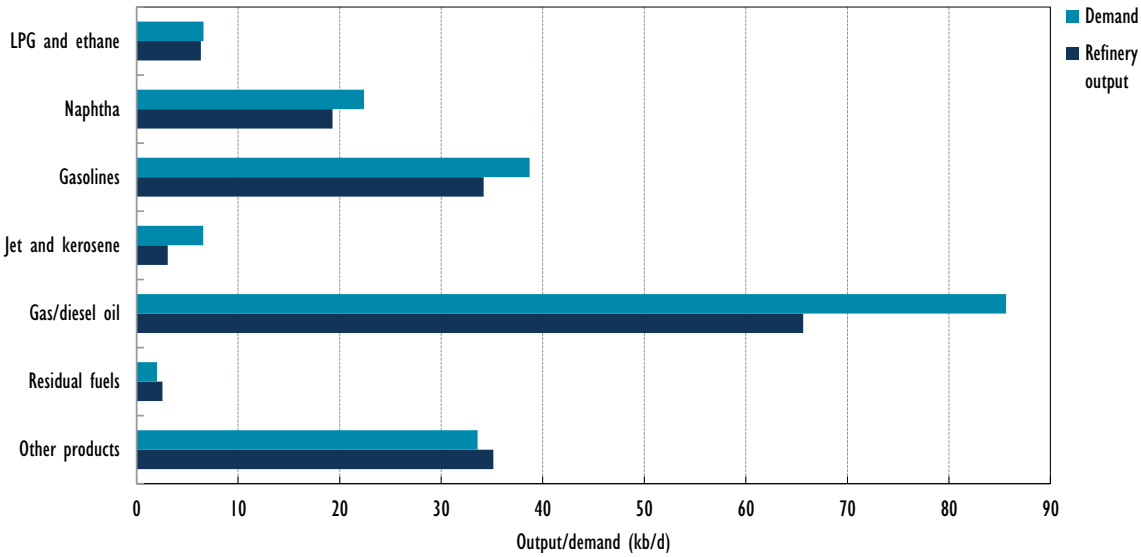
The Czech Republic's domestic refinery capacity is not sufficient for meeting oil demand in the country. Refined product output from the three domestic refineries totalled 166 kb/d in 2012. With the exception of jet fuel, domestic refinery production was able to meet 80% or more of demand for each individual product. For example, domestic production of diesel was able to meet about 85% of domestic demand, while jet fuel amounted to some 40%, requiring imports to meet the remaining share.

Figure 4.5.5 Refinery output vs. demand, 2012



Ports and pipelines

An oil products pipeline network operated by the state-owned company ČEPRO connects the main consumer regions of the country to domestic refineries. The pipeline system is also connected to the Slovnaft refinery in the Slovak Republic, which enables the import and export of oil products by pipeline. The flow direction of the product pipeline network within the Czech Republic is fully reversible.

The main crude oil supply channel is the Druzhba pipeline. Originating in Russia and transiting Belarus, Ukraine and Slovakia before terminating in the Czech Republic at Litvínov, this pipeline is able to deliver Russian and domestic crude oil to all three of the country's refineries. The Czech section of the Druzhba has a flow capacity of 9 Mt/year (180 kb/d). The flow is fully reversible on the section between Kralupy and the Slovak border.

The Ingolstadt-Kralupy-Litvínov pipeline (IKL) has a capacity to bring 11.5 Mt/year (230 kb/d) of crude oil via Germany. The IKL line connects in Germany to the international Trans-Alpine Pipeline (TAL), which has a capacity of 850 kb/d, originates in Trieste, Italy and offers the potential for diversification of imports. Approximately one-third of the Czech Republic's annual crude oil imports are typically sourced through the IKL. In 2012, MERO, the state-owned pipeline operator, became a shareholder in the TAL pipeline consortium, further increasing the relevance of this pipeline for the country's diversification of supply.

Storage capacity

Total storage capacity in the Czech Republic is some 4.2 mcm, or 26.3 mb. This is roughly split between crude oil and refined products.

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MERO and ČEPRO provide storage facilities of crude and products, respectively, for the public stocks of the ASMR, as well as for industry's commercial storage needs. In addition to these storage facilities, storage capacity among industry participants totals some 3.8 mb.

MERO's crude storage capacity at the end of 2012 was 11 mb (approximately 1.73 Mt), including 1.3 mb of storage at its facilities in Vohburg, Germany. Its central tank farm near Kralupy (Nelahozeves), which was fully modernised in 2003, offers considerable scope for more capacity expansion. In 2008 two new tanks added over 1.5 mb in capacity to the site.

ČEPRO has 17 storage sites along its product pipeline network, with a total product storage capacity of approximately 11 mb. Three-quarters of ČEPRO's storage capacity is reserved for the use of public stocks, with the remainder of the capacity available for use by all fuel trading companies in the Czech Republic. As well as stockholding, ČEPRO is a refined product trading company, which facilitates its ability to ensure necessary product stock turnover.

Decision-making structure

The chair of the ASMR serves as the head of the national emergency strategy organisation (NESO) and is responsible for initiating and co-ordinating a response to an oil supply disruption. The ASMR is responsible for stockpiling and securing supply of the main resources considered essential for the protection of public interests during crises. While ASMR reserves include agricultural goods, metals and industrial materials, oil stocks account for a majority of the overall reserves held.

Act 189 of 1999 on Emergency Oil Stocks and Managing States of Oil Emergency is the legal basis for emergency policy in the Czech Republic, providing the principle statutory authority for the ASMR's role in an oil emergency.

Act 189 specifies that ASMR oil stocks must cover no less than 90 days of net imports, as required by the European Union, while also requiring that levels be no less than the amount necessary for the Czech Republic to meet its IEA stockholding requirement. The chair of the ASMR is able to draw upon stocks held in excess of the legal minimum level required by law, providing the chair with the ability to respond to domestic supply issues with loans to industry or to rapidly participate in an IEA collective action without seeking the approval of the Czech government. In a situation which would require public stocks to be drawn below this level, the chair would submit proposals to the government specifying the use of emergency oil reserves and possible demand restraint measures. However, subject to certain conditions, the chair of the ASMR can respond to an IEA collective action without governmental approval even in situations that would bring stock levels below the 90-day limit.

Within the ASMR, the Oil Security Division has the leading role in co-ordinating the NESO and liaising with industry and the IEA. The Ministry of Industry and Trade and the Czech Statistical Office also play central roles in the NESO body. The wider NESO structure includes other ministries as well as industry representatives, and meets at least once a year.

Stocks

Stockholding structure

The Czech Republic uses the public stocks of the ASMR to fully meet its minimum stockholding obligation as a member of the IEA and the European Union. The ASMR typically holds stocks in excess of the minimum 90 days of consumption required by law. This allows flexibility in order to facilitate stock turnover while consistently maintaining more than the minimum level.

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There is no stockholding obligation on industry, but in a declared state of emergency the government has statutory powers over industry's commercially-held stocks.

Crude or products

Roughly 55% of the Czech Republic's emergency reserves (the oil stocks counting towards meeting its stockholding obligation according to IEA methodology) are held in the form of refined product. The composition of ASMR stocks is legally limited to a maximum of 60% crude or semi-finished products, and at least 40% of refined petroleum products.

The ASMR total public stocks at the end of 2012 amounted to 15 mb, roughly half of which was crude oil. Of the remaining 50% made up of refined products, more than half were in the form of diesel oil.

Location and availability

The ASMR does not hold storage capacity itself: volumes of public stocks are stored on behalf of the ASMR by designated storage operators and refiners. For the most part, the state-owned companies MERO and ČEPRO hold the ASMR stocks of crude and refined product, respectively. Storage capacity used for ASMR stocks must meet certain requirements regarding minimum size and drawdown rates. All volumes of ASMR crude oil and most product stocks (95%) are held in separate tanks.

While the Czech Republic does have bilateral stockholding agreements with Germany and the Slovak Republic, no stocks are currently being held under these bilateral arrangements.

Stockholding ticket arrangements are not used in the Czech Republic.

Monitoring and non-compliance

The ASMR is responsible for monitoring quantities and qualities of stocks held by storage operators on its behalf. It must also report total stock levels and composition to both the Czech government and the European Commission.

Crude oil and product stocks held by MERO and ČEPRO are monitored electronically on a daily basis. The small volume of stocks held elsewhere is verified monthly on an accounting basis. Each year, one-third of the stocks is physically checked by the ASMR.

Stock drawdown and timeframe

Because the ASMR typically holds stocks above the minimum level required by law, the Czech Republic is able to respond rapidly in the event of a disruption – without having to wait for government approval or an emergency declaration.

In a drawdown of public stocks, whether directed by the ASMR chair or through government approval, volumes may be either sold in a tender process or offered on loan. The ASMR posts such offers on its website and market participants are expected to address the ASMR directly. Loans are the preferred method of release, and are subject to a fee ranging from 0.9% to 1.2% of the market value of the oil. Establishing a date for the replenishment of oil stocks borrowed is an integral part of the contractual conditions, as are penalties for breach of contract. The maximum drawdown rates of public stocks are estimated to range from 125 kb/d to 185 kb/d for crude oil (depending on the pipeline used) and some 630 kb/d for finished products, well above the country's total daily oil consumption.

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Financing and fees

Public stocks are financed by the state budget. The annual financial costs of purchasing, storing and logistics and management of public emergency stocks amount to EUR 7-8/tonne.

Other measures

Demand restraint

In a severe emergency, the Czech Republic would likely use demand restraint measures in conjunction with the drawdown of public stocks.

The first step would be soft measures, such as educating the public about fuel-efficient driving techniques or calling for increased use of public transportation and carpooling.

Hard demand restraint measures available to the ASMR include limiting motor vehicle speed and imposing driving restrictions (only on certain days or for specific kinds of transportation or based on odd/even car plate numbers). In more extended disruptions, fuel rationing is also available as a policy measure; it would consist of a card system for priority users and coupon distribution to private vehicles. In a declared emergency, the government also has the power to order private companies to draw down their stocks.

Legislation assigns responsibility for ensuring compliance with these different measures to various components of the Czech government, such as the police and transportation boards, which have the authority to impose fines for violations. The ASMR, in conjunction with the Czech Statistical Office, is responsible for monitoring the effectiveness of the measures.

Fuel switching

The potential to switch away from the use of oil to another fuel source in the short term is insignificant in the Czech Republic. The bulk of oil consumption (63%) is in the transport sector, where there is no capacity for short-term switching. It is estimated that less than 6% of the oil consumed in the industry and transformation sectors could potentially be switched to another fuel, equating to less than 4 kb/d.

Other

Short-term surge production capacity in the Czech Republic is considered insignificant and not a potential emergency response measure.

Gas

Market features and key issues

Gas production and reserves

Only a small fraction of the Czech Republic's natural gas demand is met from domestic production. In 2012, some 200 million cubic metres (mcm) of gas was produced, meeting roughly 2% of demand. This is mainly produced in the South Moravian Region and, to a lesser extent, from gas taken from hard coal mines in Northern Moravia.

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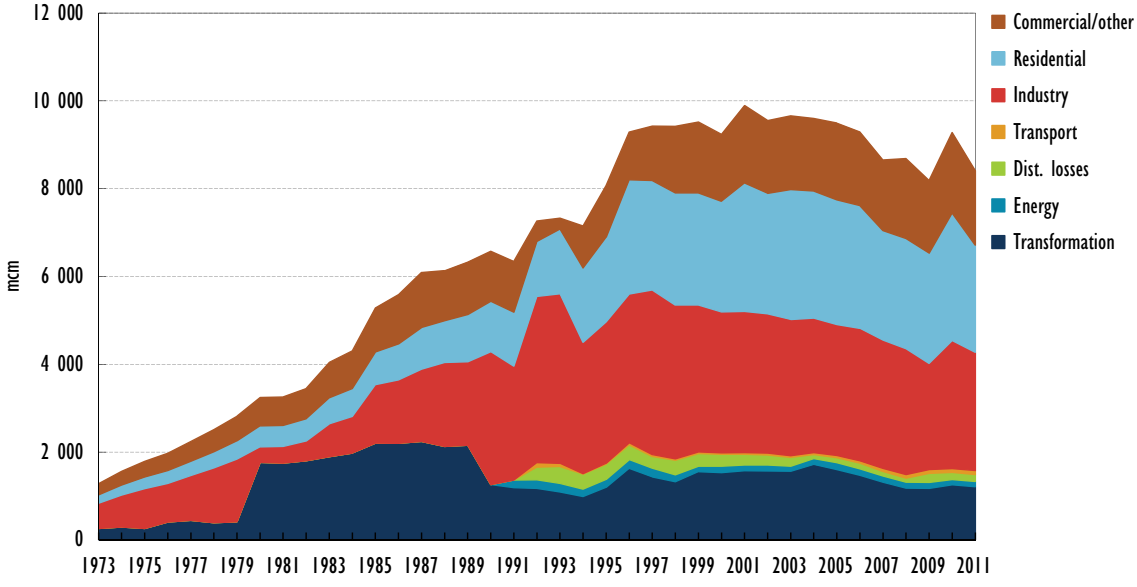
Gas demand

In 2011, demand for natural gas was just over 8.4 bcm. Industry is the primary user of gas in the country, representing 32% of total consumption. Residential users make up the second largest group, representing 29% of gas use, primarily for heating. The transformation sector accounted for 14% of gas use, where gas-fired generation is mainly used for meeting peak electricity demand.

Daily gas consumption in 2011 ranged from a minimum level of 10.4 mcm/d in the summer to a peak of 50.8 mcm/d in the winter. Winter consumption typically varies within a range of 30 to 65 mcm/d because of a relatively high seasonality of gas demand. The highest daily peak was reached in January 2006, when temperatures dropped to -16.9 °C and gas consumption reached 67.6 mcm/d.

Figure 4.5.6 Natural gas consumption by sector, 1973-2011



Gas import dependency

Historically, all gas imports came from Russia. Following efforts in the late 1990s to diversify supply, the Czech Republic began importing from Norway. In the early 2000s Norwegian gas reached a quarter of total imports, but its share in total imports has since declined. In 2008, 22% of gas imports came from Norway. Physically, all natural gas used in the Czech Republic comes from Russia owing to swap operations.

Gas company operations

In line with the liberalisation of the natural gas market under European Directive 2003/55/EC, each of the vertically integrated companies has been unbundled. RWE Transgas, the dominant importer of natural gas into the Czech Republic, has been split into a transmission system operator (TSO), RWE Transgas Net, a gas storage operator, RWE Gas Storage, the remaining part carrying on the business of natural gas wholesales. In 2012, seven distribution system operators were selling gas to customers, with three majors serving nearly 75% of the market: RWE (33.3%), JMP Net (21.8%) and SMP Net (18.1%).

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Gas supply infrastructure

Ports and pipelines

RWE Transgas Net, the Czech Republic's TSO, manages a domestic and transit pipeline network with three interconnection points. This is used both to transport natural gas for consumption in the Czech Republic (8.7 bcm/year) and for transit of around 30 bcm/year of Russian gas to other end-user markets further west. Transit gas arrives at the incoming transfer stations of Lanžhot and Olbernhau and departs from the outgoing transfer stations in Waidhaus and Hora Svaté Kateřiny.

Linked to the pipeline construction of Nord Stream (through the Baltic Sea from Russia to Greifswald, Germany) and OPAL (connecting Nord Stream, through Germany, to Hora Svaté Kateřiny), the Gazelle pipeline project, which became operational in January 2013 with a capacity of 30 bcm/year, connects Hora Svaté Kateřiny. to Waidhaus. This could potentially lead to a shift of transit flows through the Czech Republic, moving amounts of Russian gas that currently enter the country at Lanžhot (after transiting through Ukraine) to the Olbernhau entry point.

An interconnector between Poland and the Czech Republic became operational in April 2012.

Storage

There are three storage system operators (SSOs) in the Czech Republic: RWE Gas Storage, MND and SPP Bohemia. Between them, the three companies own and operate eight underground storage facilities in the country. The Dolní Bojanovice site is used exclusively for supplying the Slovak market. At the same time, a storage facility in Slovakia, at Láb, is used for supplying the Czech market.

The gas industry has recently finished projects to expand gas storage; capacity at three of the country's eight underground storage sites has been raised to a total of 3.5 bcm (from a previous total of 2.9 bcm) and the total withdrawal capacity increased from 56.2 mcm/d to 65.6 mcm/d. This compares to the country's winter consumption range of 30 to 65 mcm/d and a single day record high of 67.6 mcm/d. When completely full, storage is able to supply peak demand for approximately 50 days.

Emergency policy

The Czech Republic maintains a high degree of natural gas supply security through a combination of several measures, including using long-term supply contracts, having a relatively high capacity of underground commercial gas storage, and requiring transmission and distribution system operators to comply with the safety standards of the supply infrastructure. It seeks to improve security of supply through capacity extensions at a number of storage facilities and increased flexibility in its gas network, including reversibility of gas flows throughout the transmission system and expanding interconnectors to neighbouring countries.

Following the January 2009 gas crisis in Europe, the Czech government put in place, over a short period of time, a response plan for dealing with a reduction in gas supplies. This relies on co-ordination with industry in order to optimise gas storage use and regulate demand-side measures in a crisis. This plan sets measures and actions to be taken during the periods of early warning and sets emergency crisis levels.

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Emergency response measures

There are no emergency reserves of natural gas in the Czech Republic, as all storage is used for commercial purposes.

The early warning system established in 2009 requires transmission and distribution system operators and all gas traders to report any indications of potential disruption to supplies. In the event of a disruption to gas supplies, crisis severity levels would be used to determine the level of restrictions or cut-offs to end-users. Customers are divided into groups according to the volume and type of consumption (e.g. gas used for heating or production; the importance of use for ensuring functioning of the state). Disruptions would be rated on their level of severity, determining the degree to which specific consumer groups would have their supplies restricted or stopped. There are five levels of consumer groups for which supplies would be reduced and another five levels in which supply cut-offs would be imposed. The last consumer group consists of small businesses and households and would be supplied in all but the most severe of disruptions.

There is no programme in place in the Czech Republic to encourage or otherwise require users of gas to switch to other fuel sources in the event of a gas supply disruption. The potential for short-term switching from gas to other fuel is limited. In the transformation sector, most gas-fired power stations are used to meet peak electricity demand and do not have the capacity to switch fuel sources.

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Denmark

Key data

Table 4.6.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	121.7	363.0	388.1	254.8	221.1	201.2	142.8
Demand (kb/d)	192.4	210.0	183.5	167.5	164.0	158.5	150.7
Motor gasoline	37.2	45.8	43.4	36.5	34.9	33.0	-
Gas/diesel oil	92.3	86.7	83.3	85.8	83.6	80.9	-
Residual fuel oil	28.8	22.5	19.3	13.4	11.5	10.9	-
Others	34.2	55.0	37.4	31.7	33.9	33.7	-
Net imports (kb/d)	70.7	- 153.0	- 204.6	- 87.3	- 57.1	- 42.7	7.9
Import dependency (%)	36.8	- 72.9	- 111.5	- 52.1	- 34.9	- 26.9	5
Refining capacity (kb/d)	187.0	135.0	176.4	179.5	179.5	179.5	-
Oil in TPES (%)**	46	43	40	35	36	36	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.6.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	3 137	8 153	10 447	8 220	7 065	6 416	4 260
Demand (mcm/y)	2 058	4 894	4 987	4 947	4 182	3 899	3 181
Transformation	537	2 413	2 353	2 304	1 742	0	-
Industry	605	856	798	796	793	0	-
Residential	436	708	772	825	691	0	-
Others	480	917	1 064	1 022	956	0	-
Net imports (mcm/y)	- 1 079	- 3 259	- 5 460	- 3 273	- 2 883	- 2 517	- 1 079
Import dependency (%)	- 52.4	- 66.6	- 109.5	- 66.2	- 68.9	- 64.6	- 34
Natural gas in TPES (%)	11	24	23	23	21	20	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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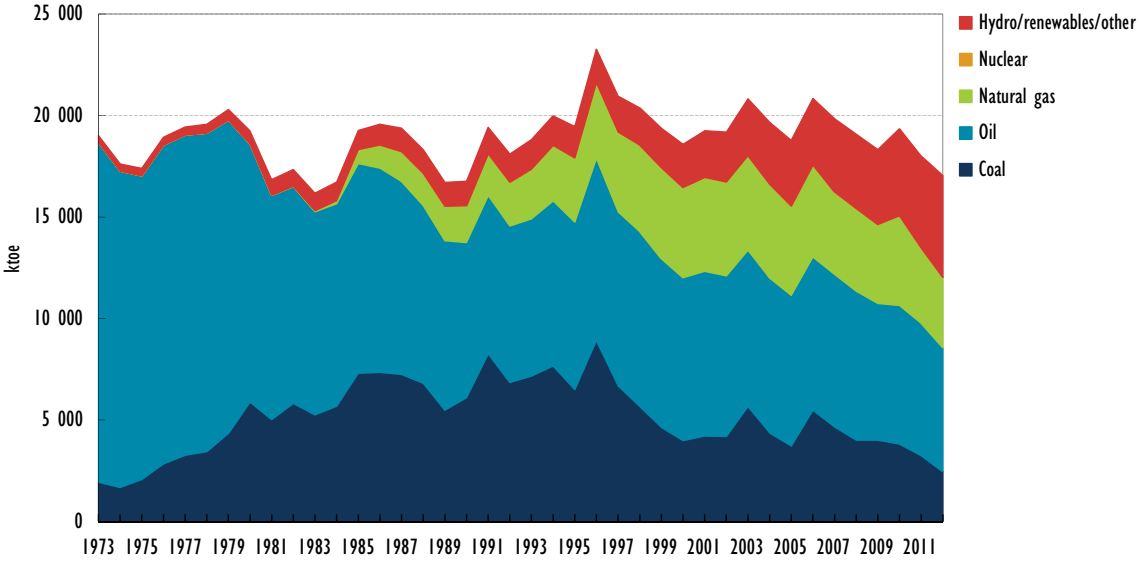
Figure 4.6.1 Total primary energy source (TPES) trend, 1973-2012



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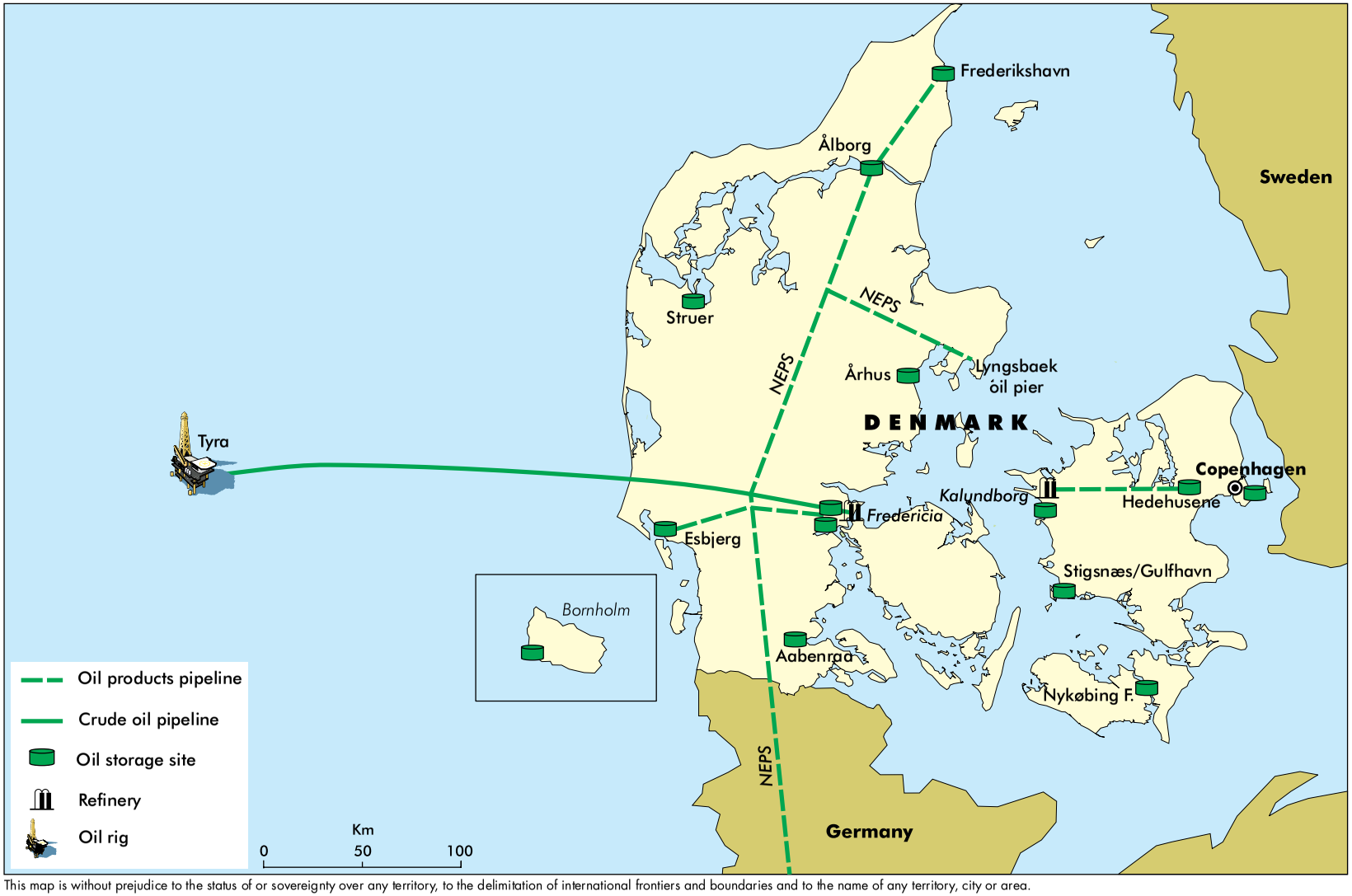
Map 4.6.1 Oil infrastructure of Denmark



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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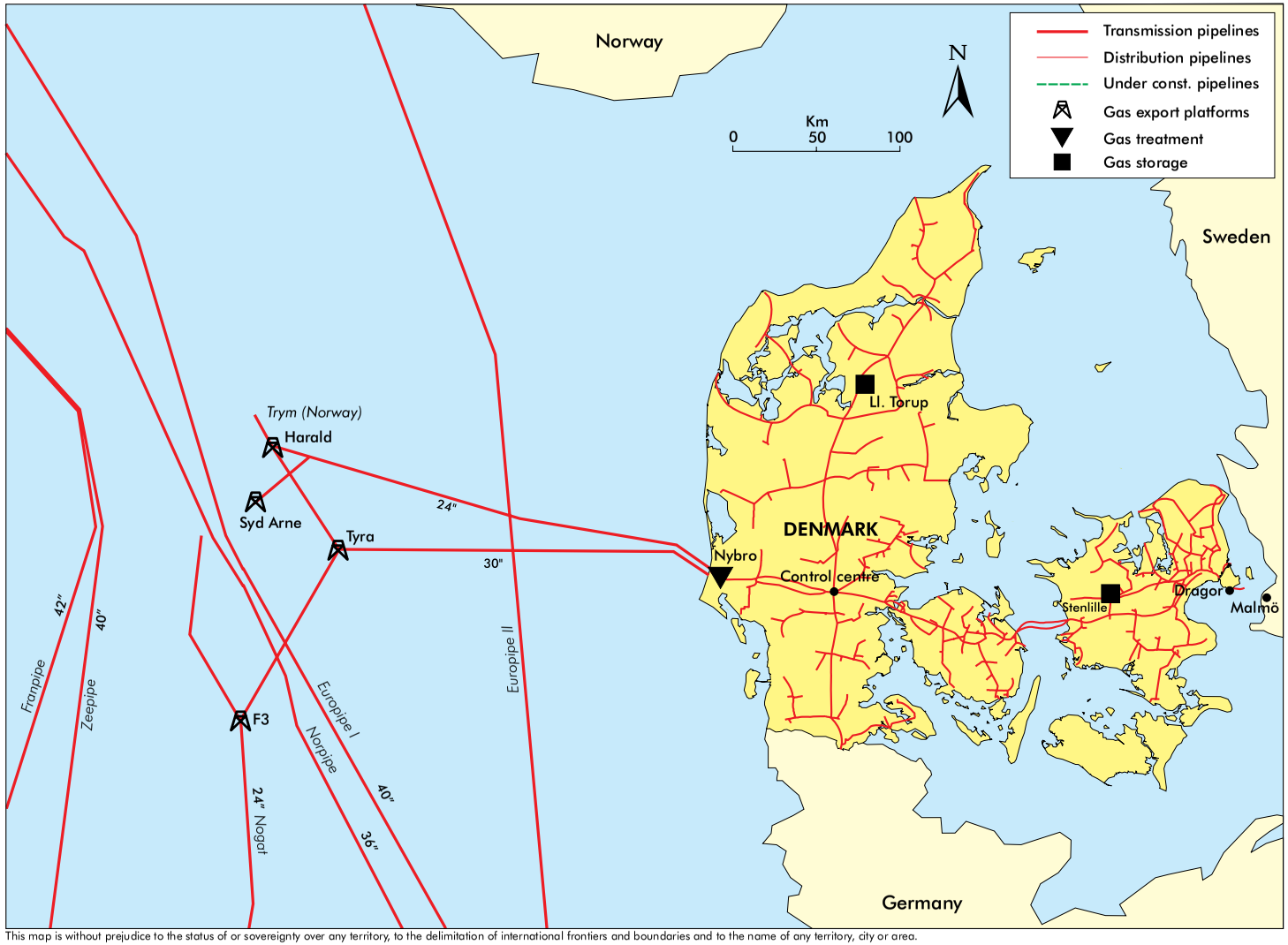
Map 4.6.2 Gas infrastructure of Denmark



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Country overview

Oil represented 36% of Denmark's total primary energy supply (TPES) in 2012, while gas represented 20% in the same year. The combined share of the two fuels in the supply mix has remained relatively stable over the past three decades, at around 60% of TPES, although oil's share has been reduced dramatically from the nearly 90% it represented in the early 1970s. At the same time, Denmark has one of the lowest energy intensities in the world, and while its economy has grown by 78% since 1980, its energy use has remained almost unchanged over the same period. Denmark is now considering the introduction of a long-term target to become fully independent of fossil fuels by 2050.

Total oil demand, nearly 160 thousand barrels per day (kb/d), is expected to decline in the coming years, reaching an estimated 150.7 kb/d in 2018. Demand for natural gas, just under 4 billion cubic metres (bcm) in 2012, is expected to decline in the coming years largely because of a shift towards renewable energy in the power sector.

Denmark is a net exporter of oil and natural gas. This is however expected to change in the case of oil in the very near future: in 2018 the demand for oil is already expected to overtake the country's indigenous production by 7.9 kb/d (resulting in an import dependency of 5%). Denmark will still remain self-sufficient in natural gas at least until 2020. Extending self-sufficiency beyond these dates will for the most part depend on future technological developments upstream, but even once the country becomes a net importer, this would likely only be marginal in the period prior to 2035.

As a net exporter, Denmark has no stockholding obligation to the International Energy Agency (IEA). As a member of the European Union, Denmark has a stockholding obligation of 61 days of consumption calculated on the basis of the EU Directive 2009/119 which came into force as of 31 December 2012. The government goes well beyond this, setting a compulsory stockholding obligation on industry of 73.2 days of consumption. Some 70% of this is covered by the Danish stockholding agency, FDO, largely in the form of refined products.

The Danish Energy Agency is, on behalf of the Minister for Climate and Energy, responsible for energy matters including the security of oil and gas. The DEA also has the over-all responsibility for the handling of a crisis.

With respect to security of natural gas, the transmission system operator (TSO), Energinet.dk is responsible for operational matters and preparing an annual plan for assuring security of supply. In a crisis, within the framework of the DEA's crisis management, Energinet.dk would take over the role of gas supplier to the Danish market, with an obligation to ensure supplies of gas to the non-interruptible Danish end-users. It would do this by drawing on measures only available to Energinet.dk in emergency supply situations, i.e. deliveries from the two underground storage sites in Denmark, re-routing of natural gas supply from the North Sea via the Syd Arne pipeline and limiting supplies to interruptible end-users.

Oil

Market features and key issues

Domestic oil production

Oil production in Denmark began in 1972 and rose steadily until reaching a peak in 2004, when it averaged nearly 390 kb/d. Production has since declined steeply and in

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2012 it averaged some 201 kb/d. Danish oil production comes exclusively from offshore installations in the Danish North Sea, where there are 19 producing fields. The main crude stream, Danish Crude Blend, is a medium-light sweet quality that has a high middle distillate yield. Oil production is expected to continue to decline in the coming years.

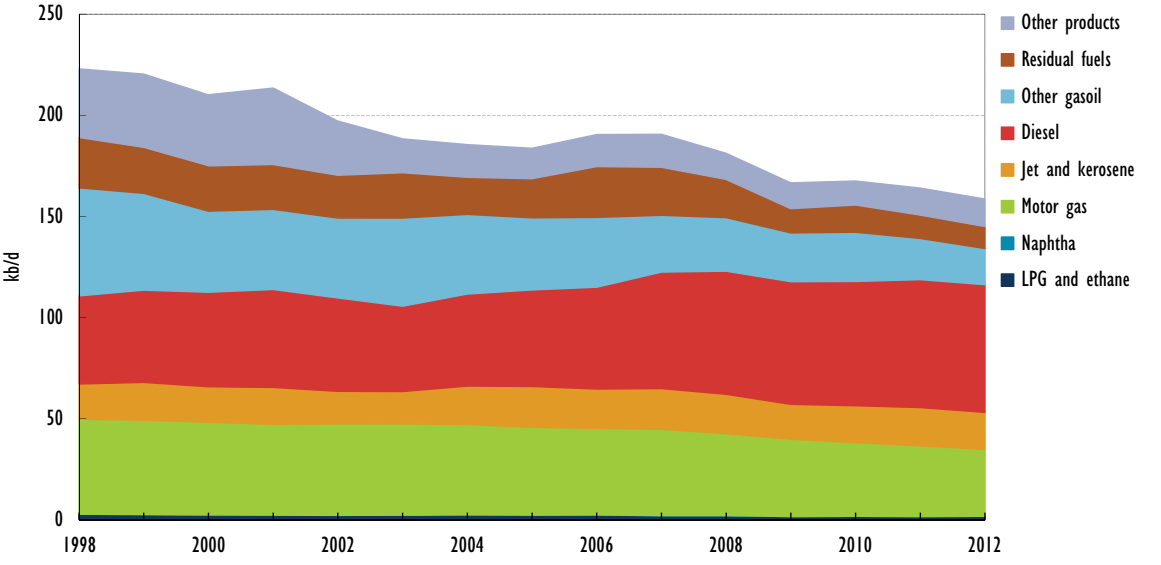
Denmark's period of self-sufficiency in oil can potentially be prolonged with additional production coming from technological developments and new discoveries. However the estimates for these resources, unlike the expected production profile, are subject to a high level of uncertainty. If realised, these would be expected to contribute substantially over the period from 2020 to 2035 and decline thereafter. Such a scenario would likely result in Denmark, alternating between being a net exporter and a (marginal) net importer of oil over this period, having oil import dependency that is growing steadily in the years after 2035.

The estimate of technological resources by the Danish Energy Agency (DEA) is based on increasing the average oil recovery rate by 5%. Currently the recovery rate (the ratio of ultimate oil recovery to total oil originally in place) of Danish oil production is relatively low, averaging around 24%. The 5% increase is expected to derive primarily from new techniques used for CO_2 injection. Government initiatives for enhanced oil recovery include an independent assessment – prepared by the North Sea Fund, the DEA and Maersk Oil and Gas – of the existing worldwide experience with different methods used to recover more oil from the fields.

Oil demand

Oil product demand in Denmark totalled some 7 million tonnes (Mt) in 2012, or an average of 158.5 kb/d. This represents a decline in total oil use at an average annual rate of 2.7% since 2001. During this period, demand for oil use in the transformation and residential sectors declined substantially. The use of fuel oil in power generation is declining and the use of heating oil is subsiding because of the increased connection of homes to district heating which is primarily fuelled by renewable energy or natural gas. At the same time, demand for transport diesel continued to grow at an average 2.5% annually in the period from 2001 to 2012.

Figure 4.6.2 Oil demand by product, 1998-2012



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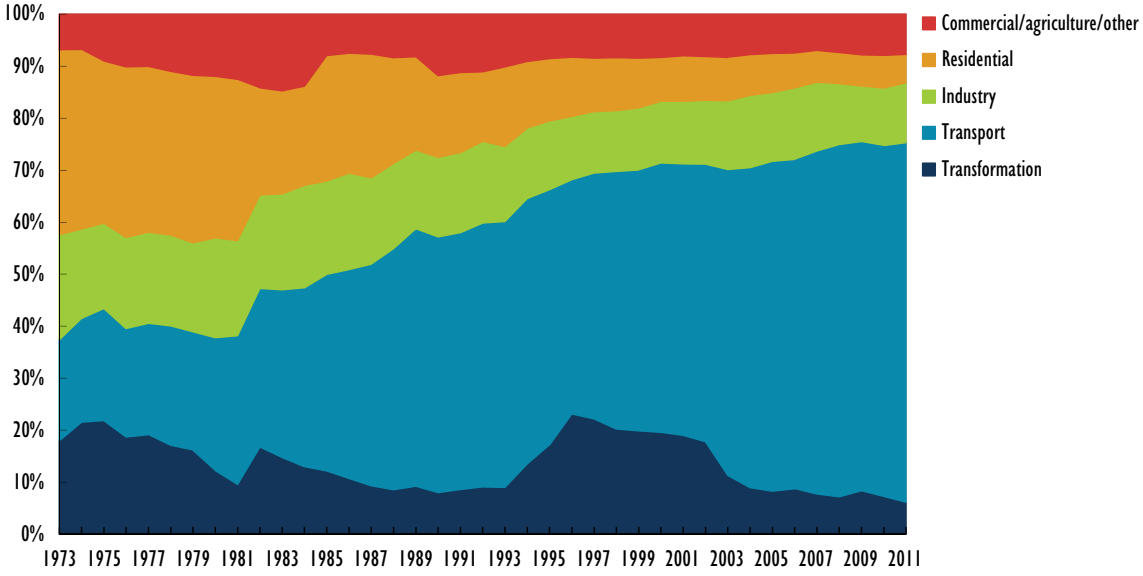
The transport sector accounts for two-thirds of all oil used in Denmark. Diesel is the single largest component in the mix of oil products used and in 2012 it represented 40% of the oil products consumed in the country. Automotive diesel has a price advantage for consumers as it has a lower tax rate than gasoline.

Figure 4.6.3 Oil consumption by sector, 1973-2011



Total oil demand is not expected to change significantly in the coming years. The DEA's projection for oil demand, which is the basis for forecasting the country's oil self-sufficiency (see section above on domestic oil production), assumes oil consumption will grow moderately, averaging 0.4% annually to 2030. However, the Danish Oil Industry Association (EOF) as well as the independent public stockholding agency, FDO, expect total oil consumption to decrease gradually in the coming decade (-0.5% annually).

Imports/exports and import dependency

Denmark's total net exports of oil, including both crude and refined product, amounted to 42.7 kb/d in 2012.

Denmark has been a net exporter of crude oil since the mid-1990s. In 2012, roughly 143 kb/d of the 201 kb/d of domestic production was exported. In the same year Denmark imported 74.6 kb/d of crude oil for domestic refining, primarily from Norway.

In terms of refined products, Denmark is a marginal net exporter (less than 1 kb/d in 2012) – a change from previous years, when Denmark was a marginal net importer. Generally, Denmark is a net exporter of gasoline and fuel oil and a net importer of middle distillates.

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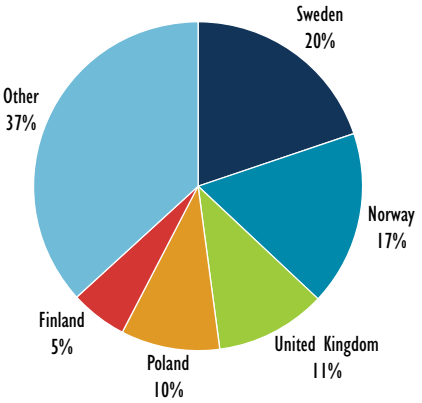
Figure 4.6.4 Oil product imports by origin, 2012



Oil company operations

Oil production on the Danish continental shelf is dominated by three groups of companies with the following operators: Maersk (the operator of 15 fields), DONG (3 fields) and Hess (one field).

In the downstream oil sector, approximately 90% of the market is represented by five companies: Statoil, Shell, Kuwait Petroleum, Uno-X and OK. All are members of the EOF. Consolidation in the Danish oil industry has continued over the past decade, with many smaller companies being purchased by the larger companies. The acquisition by Statoil of Conoco/Jet is one of the more significant examples of this consolidation in recent years. Statoil has also announced that it will put its retail and industry sales organisation into a separate, publicly traded company.

Oil supply infrastructure

Refining

In 2012, Danish refineries processed about 7.4 million tonnes (Mt) of crude oil, or just under 156 kb/d.

Denmark has two refineries, one in Kalundborg and the other in Fredericia, with a combined total crude distillation capacity of 180 kb/d in 2012. The Kalundborg refinery (110 kb/d), owned by Statoil, primarily processes Norwegian crude, but is flexible to run condensates and other crudes (e.g. Danish crude). All crude oil, including condensates, is supplied by ship. The Fredericia refinery (70 kb/d), owned by Shell, processes mostly Danish North Sea crude oil supplied by pipeline from Danish offshore production.

In comparison to Danish oil demand, the domestic refineries produce a surplus of gasoline and residual fuel oil, but do not meet the demand for middle distillates. Trade in refined products is thus necessary to balance domestic supply and demand.

Ports and pipelines

Denmark has one crude oil pipeline connecting most of its offshore production to the Shell refinery and the crude export terminal, both at Fredericia. Owned and operated by DONG Oil Pipe A/S, the pipeline is 330 km long and has a capacity of 360 kb/d.

The Northern European Pipeline System (NEPS), extends from Heide in Germany to North Jutland and is owned and operated by the Danish military forces. In addition, the FDO owns and operates a number of product pipelines in Jutland and in Zealand,

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including one from the Kalundborg refinery to the Hedehusene product terminal. This pipeline supplies a large volume of oil products to the Copenhagen area.

In addition to the ports at the refineries, the main terminals for loading and off-loading oil products on tankers are the ports of Aalborg, Aabenraa, Copenhagen and Stigsnaes. The various other ports are used only for importing oil products.

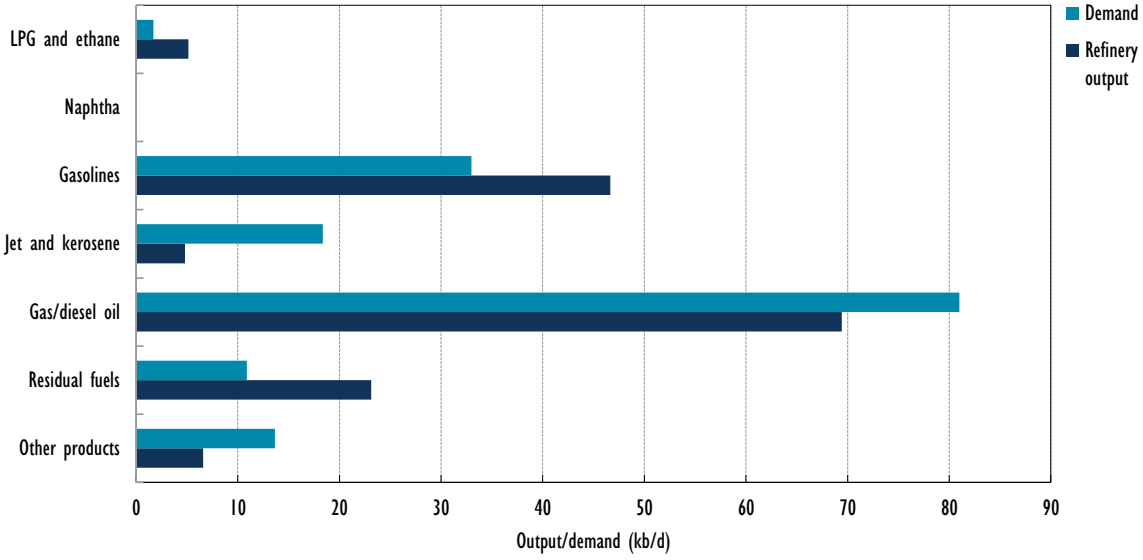
Storage capacity

The total storage capacity in Denmark is just over 49 mb (7.8 mcm). Nearly 5.9 mb of this capacity is for crude oil at the two refineries.

Denmark has a number of coastal and inland product storage facilities that also serve as terminals for the distribution system, which is mainly carried out by trucks. The major product storage sites are located at the refineries and at a major terminal on Zealand at Stigsnæs.

Approximately 12.6 mb (2 mcm) of the country's storage capacity is owned by the stockholding agency FDO. This includes a network of 15 underground storage sites, operated directly by the FDO, with total capacity of some 5.3 mb for gasoline and gasoil. The amount also includes the FDO's two above-ground storage facilities in connection with the two domestic refineries. These are integrated with the operations of the refineries and are operated by refinery personnel to facilitate the refreshment of products. In Fredericia the capacity is close to 5 mb (800 000 m³) for gasoil and heavy fuel and in Kalundborg the capacity is approximately 2 mb (330 000 m³) for gasoil.

Figure 4.6.5 Refinery output vs. demand, 2012



Decision-making structure

The Danish Minister for Climate and Energy is responsible for energy matters, including the security of oil supply and relations with the IEA and the European Union. Within this ministry, the DEA handles all matters regarding energy, including the preparation of an implementation plan of response measures. Denmark's response to an oil supply crisis would be the use of emergency oil stocks primarily held by the stockholding agency, FDO. Specific demand restraint measures have not been prepared and would not be

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a part of an initial response. However, in a severe and long-lasting crisis light-handed measures would likely be considered to supplement the use of emergency stocks.

As an integrated part of the DEA, the Danish national emergency strategy organisation (NESO) consists of an emergency unit and data unit, each staffed with two part-time employees, and is the core body to co-ordinate issues among all stakeholders such as the press officer of the DEA and various ad hoc groups that could be established in the case of an oil crisis. The emergency unit handles all matters regarding the compulsory stockholding obligation (CSO), tasks related to the FDO and dialogue with the companies regarding their CSO.

In a crisis, the NESO would be expanded, as necessary, with other DEA staff in order to implement emergency measures in co-operation with other energy sector operations. It would convene meetings of the Danish Oil Advisory Board in order to create an opportunity for relevant authorities – including the oil industry – to assess the crisis, evaluate response options and define implementation measures.

In a crisis, the DEA would propose emergency response measures to the Minister for Climate and Energy through the ministry. In preparing such a proposal, assuming that this only consists of release of emergency stocks, the DEA would communicate with the FDO. If a decision is needed quickly, it would not be necessary to have a meeting of the Danish Oil Advisory Board prior to a decision, but such a meeting would then be held afterwards. The minister would, in connection with the decision on the response measure, inform the Danish parliament's energy committee about the situation.

Stocks

Stockholding structure

Because of its status as a net exporter, Denmark currently has no stockholding obligation to the IEA. According to EU Directive 2009/119 which was implemented as of 31 December 2012 Denmark has an obligation to hold 61 days of consumption. However, Denmark has decided to hold emergency stocks at a level of 73.2 days of consumption.

The private sector covers the entire stockholding obligation, with the bulk of this covered by the non-governmental stockholding association (established by the private sector in 1964). The FDO is managed and financed by oil companies and operates the stockholding on their behalf.

Crude or products

The FDO holds about 70% of the Danish CSO, mostly as finished products. Individual companies hold the remaining 30% in their commercial tanks. At the end of 2012, the FDO oil stocks totalled some 7.6 million barrels. This figure includes about 0.8 mb (110 000 m^3) of crude oil stored at the refinery in Kalundborg. It also includes 0.9 mb (135 000 m^3) of feedstock (straight run fuel) held at the Fredericia refinery which is in a solid form and requires a heating process before being ready for release (within six weeks).

Location and availability

In accordance with a bilateral agreement, Danish regulations stipulate that compulsory stocks must be stored in Denmark or in another EU member state under a bilateral agreement. Without this being stipulated in the regulations, it has been common practice that companies will not fulfil more than 10% of their obligation through stocks held abroad.

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The FDO-owned storage capacity (12.6 mb in total) includes a network of 15 underground storage sites with a total storage capacity of 5.3 mb for gasoline and gasoil.

Monitoring and non-compliance

The DEA is responsible for monitoring compulsory stocks. All companies, including the FDO, report monthly data on their stocks to the DEA, which calculates the yearly stockholding obligation for each company according to the compiled figures.

If the stockholding companies do not hold the required stocks, the DEA may report the company to the police.

Stock drawdown and timeframe

The government of Denmark has statutory powers to draw down stocks, including those held by the FDO on behalf of the companies in order to participate in an IEA co-ordinated response.

When the need arises for a compulsory stockdraw, the DEA submits a proposal for the measures that are to be used to the Minister for Climate and Energy. The DEA also co-ordinates with the FDO. Ministerial decisions on the required stockdraw are expected to be taken within 24 hours. They are then communicated to the DEA, which ensures implementation in co-operation with the FDO.

Regardless of whether the released stocks are FDO stocks or company stocks such release will necessitate a temporary reduction of the companies' CSO.

Trucks can be loaded directly at the depots of most of the FDO underground storage sites and the FDO is also able to pump oil products to bigger terminals for loading. Pumping rates vary between 18 and 90 kb/d (120 and 600 m^3/h).

Financing and fees

All Danish stocks are held and financed by private parties; there is no financial support from the government for the industry's stockholding obligations. The costs of holding compulsory stocks are included in the companies' price calculations and may eventually be borne by consumers.

Other measures

Demand restraint

In a severe and long-lasting oil supply disruption, Denmark would consider light-handed demand restraint measures as supplementary measures to the use of compulsory stocks. The first demand restraint measures that would be considered are likely to be guidance and appeals to the public through the media for voluntary measures. More systematic information campaigns could be implemented (e.g. about eco-driving, the promotion of public transportation and carpooling), potentially combined with measures to make alternative forms of transportation more attractive. Subsequently, compulsory measures may be considered, likely to be first directed at public authorities, and thereafter directed at the general population or selected parts of the population.

The legal framework for enacting any demand restraint measures is the Consolidated Act No. 88 of 26 February 1986 on Supply Measures. Under this act the minister may, in the event of an internationally-induced crisis, stipulate provisions about the use, distribution, price equalisation and location of stocks of commodities.

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Fuel switching

The Danish potential for fuel switching – from oil to coal or natural gas – in power and heating plants is limited. The price structures for oil, coal and other fuels have already resulted in most of this potential being realised. The large central power plants are not oil-fired apart from peak and reserve capacity which cannot be switched to other fuels. Likewise, some heating plants are oil-fired, but cannot be switched to other fuels.

Other

There is no legislation which covers the issue of surge production. Danish oil production in the North Sea is normally operated at full capacity and possibilities for surge production have not been identified.

Gas

Market features and key issues

Gas production and reserves

In 1984 Denmark began producing natural gas from the North Sea and has been a net exporter of natural gas ever since. Production comes primarily from the Tyra, Halfdan, Dan and Tyra Southeast Fields, which account for three-quarters of total Danish gas production. Approximately 10% of total production is used in the field as fuel, for injection or is flared. The proportion of natural gas used as lift gas in wells with increasing water production could grow significantly in the coming years as oil extraction becomes increasingly difficult from ageing fields.

Production peaked in 2005, with a total of 10.4 bcm produced. Total production has declined steeply since and was some 6.4 bcm in 2012.

While Danish gas production is expected to continue to decline sharply in the immediate short term, it will increase substantially in 2014 and 2015 because of the development of new and existing fields. Based on the DEA's expected production profile, Denmark is expected to remain a net exporter of gas up to and including 2020. The gas consumption forecast associated with this estimate is for a decline in gas demand, averaging roughly 1.3% annually to 2030.

As with oil production, there is the potential for prolonging the period of self-sufficiency in gas supplies. When including technological and prospective resources, the DEA estimates that Denmark will be a net exporter of gas beyond 2030.

Gas demand

Demand for natural gas in 2011 was 4.2 bcm. In that year, the bulk of gas consumption (42%) was used for power generation in the transformation sector. Industry made up the second largest group, representing 19% of gas use, while the energy sector, where gas is used for oil extraction, represented another 16%.

Daily gas consumption in Denmark normally ranges from a level of around 4 million cubic metres per day (mcm/d) in the summer to 20 mcm/d in the winter. The expected maximum daily consumption when temperatures reach -13°C is about 25.3 mcm/d.

Future Danish gas consumption is expected to decrease by 1.3% annually from 2010 to 2030. This would infer a gas demand of some 4 bcm in 2015 and 3.8 bcm in 2020. The reason for the forecast decline is greater energy efficiency, a decrease in gas use at

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power plants, a decrease in gas consumption at decentralised combined heat and power (CHP) plants as a consequence of wind power development and a shift towards biogas.

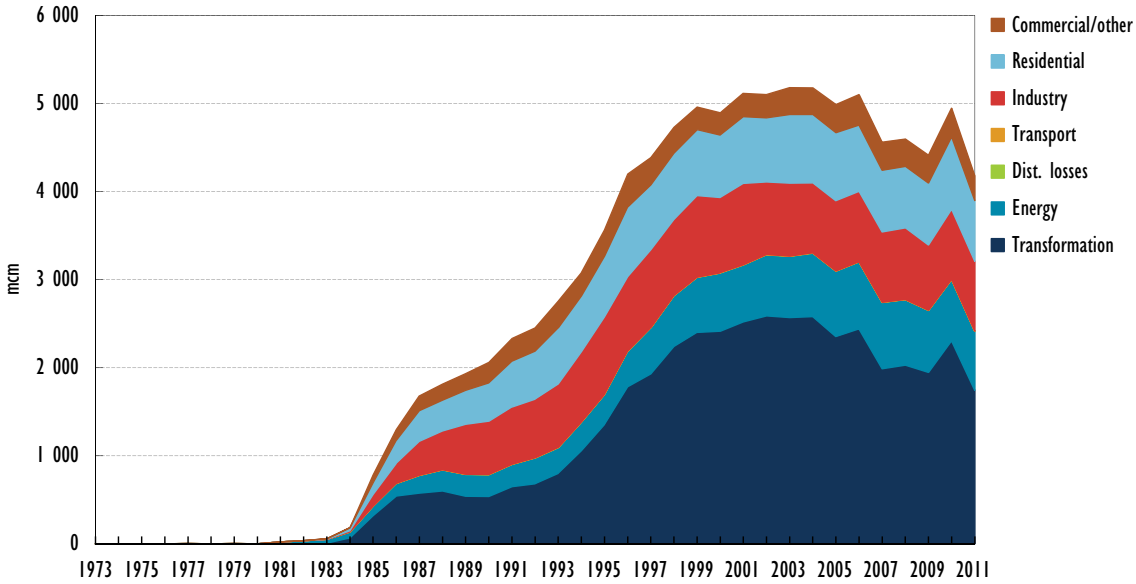
Gas import dependency

Denmark is a net exporter of natural gas. In 2011, some 3.1 bcm of the total production of natural gas was exported to Sweden (1.3 bcm), Germany (1.1 bcm) and the Netherlands (700 mcm).

Gas company operations

The Danish natural gas market is liberalised and there are no barriers to new entrants. The state-owned TSO, Energinet.dk, owns and operates the transmission network across the country and there are three distribution network operators as well as five active players in the retail market.

Figure 4.6.6 Natural gas consumption by sector, 1973-2011



Gas supply infrastructure

Ports and pipelines

The Danish gas transmission system consists of upstream pipelines in the Danish part of the North Sea and onshore transmission pipelines. The transmission pipelines go north to south (Aalborg-Ellund) and west to east (Nybro-Dragør); the distribution pipelines are made up of a grid of pipeline systems to consumers. In addition, the natural gas transmission system consists of a gas treatment plant (Nybro) and two underground gas storage facilities (Stenlille and Lille Torup).

The Danish gas transmission grid is connected to the German gas transmission grid at Ellund on the Danish-German border and to the Swedish gas system at Dragør. Sweden is solely supplied with gas via the Danish gas system.

Natural gas from the Danish section of the North Sea is transported through two offshore pipelines from the Tyra and Syd Arne Fields to the shore north of Esbjerg at a maximum pressure of 138 bar. In summer with lower daily quantities, the outlet pressure

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is reduced to minimise the energy consumption for compression. In winter, the pressure is increased to also ensure large volumes of line pack (i.e. the gas volume naturally stored in the actual gas pipelines) for use in the event of disruptions and emergency situations. The Tyra-Nybro pipeline has a capacity of approximately 28.5 mcm/d (27 million Nm^3/day); the Syd Arne-Nybro pipeline capacity is 13.7 mcm/d (13 million Nm^3/day).

On shore, the natural gas passes through a gas treatment plant in Nybro. Here, the quality of the gas is checked and measured, and pressure is reduced to the maximum pressure for land pipelines of 80 bar. The plant can also reduce the content of impurities such as heavy hydrocarbons, and remove any hydrogen sulphide if necessary for the gas to comply with the agreed specifications. If the gas is to be cleaned, only reduced volumes can be supplied (about 50%).

The security of supply was improved with the Syd Arne pipeline, constructed in 1999 which made it possible to redirect gas production from the Tyra facilities to the Syd Arne pipeline. In addition, a new pipeline was commissioned in 2004, connecting the Tyra facilities to the F/3 platform in the Dutch sector. The pipeline allows the transport of gas through the existing Northern Offshore Gas Transport (NOGAT) pipeline to the Netherlands for the purpose of selling gas to the Dutch market. It is not currently possible to import gas into Denmark via this pipeline.

Storage

There are two natural gas storage facilities in Denmark with a total capacity of 1 bcm of working gas. These storage facilities are primarily used to even out seasonal fluctuations, as the daily demand for natural gas during the winter can reach levels six to seven times that of summer. The storage can also be used as emergency storage facilities in case of interruptions to gas deliveries. The TSO, Energinet.dk, has access to a volume of this gas as part of the available emergency response measures.

The storage facility in Lille Torup (northern part of Jutland) is owned by Energinet.dk Gas Storage and comprises seven salt caverns with a total firm working volume of 420 mcm. Firm injection capacity is 3.6 mcm/d and firm withdrawal capacity is physically 14 mcm/d. However, owing to restrictions in the transmission system, only 8 mcm/d can be withdrawn. Energinet.dk Gas Storage has decided to begin re-leaching a cavern which will result in more working volume capacity.

The storage facility in Stenlille (western part of Zealand) is an aquifer storage owned by DONG Energy. The storage has a total firm working volume of 588 mcm. Firm injection capacity is 4.8 mcm/d and firm withdrawal capacity is physically 11 mcm/d. However, because of restrictions in the transmission system the storage is only able to offer 9.5 mcm/day. The Stenlille Gas Storage Facility can be relatively easily expanded to a working volume of up to 750 mcm.

Emergency policy

The responsibility for Denmark's security of supply lies with the Danish Energy Agency on behalf of the Minister for Climate Change and Energy. Within this framework the Danish TSO, Energinet.dk, has responsibilities for operational matters. This consists of observing minimum standards and preparing an annual plan for the security of gas supplies. The plan must describe how security of supply is ensured during the period under review and how it will be ensured in the coming year and next ten years. In addition, the plan must account for the means used to maintain security of supply in emergency supply situations.

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Security of supply has been determined by the administration on the basis of an objective which stipulates that, in the event of full or partial interruption of gas supply to the Danish market, the supply of uninterruptible consumers must, at a minimum, be maintained for 3 days during particularly cold periods (defined as a daily mean temperature of -13 °C), which, on average, occur every 20 years, and for 60 days during a normal-temperature winter (corresponding to the expected repair time needed after the breakdown of an offshore pipeline).

Based on historical data, a daily mean temperature of -13 °C is expected to result in Danish gas consumption of approximately 25.3 mcm/d (24.0 million Nm^3/day). In an emergency supply situation Energinet.dk would take over the supplies to the Danish gas market from the market players. To this end, Energinet.dk purchases alternative transport capacity in the Syd Arne pipeline, reserves capacity in the storage facilities and enters into agreements on interruptibility with a number of major consumers. In order to fulfil the security objective (3 days of extreme winter, 60 days of normal winter), every year Energinet.dk determines the gas volumes to be covered by each of these emergency measures.

In a worst-case-disruption scenario, supplies would be disrupted on the largest source of supply (supplies via the Tyra-Nybro pipeline). In such a case, Energinet.dk can maintain the supply of gas to Denmark using supplies from storage, emergency supply from Tyra via Harald through the Syd Arne-Nybro pipeline, and interruption of the largest natural gas consumers based on interruptible contracts.

Emergency response measures

Energinet.dk has access to a total of approximately 215 mcm of strategic storage capacity filled with gas. This includes amounts reserved directly by Energinet.dk (the amount is determined each year) and volumes made available from shippers' storage filling requirements. The majority of the capacity in Stenlille and Lille Torup has been sold under filling requirements such that the storage customers commit themselves to maintaining a certain stock volume during the year against a discount. Energinet.dk compensates the two storage companies for this and thus has additional stock volume for emergency situations at its disposal. Each year on 1 March 12% of the shippers' storage capacity must be left in storage.

Energinet.dk has agreements with approximately 40 of Denmark's largest gas consumers concerning the interruption of supplies during an emergency situation.

Approximately 20% of the total Danish gas consumption during winter (January and February) can be interrupted through these agreements. The terms of agreement can cover either an interruption of gas delivery after three hours or after three days, or a combination of these. Some consumers have agreed to a 100% interruption of their consumption while others reduce their consumption only partly. Thus, most of the CHPs, in such situations, plan to temporarily stop their electricity production and reduce their gas consumption to cover heat production only. In general, the interruptible end-users plan to reduce their consumption by as much as 75% in case of such an emergency supply situation.

Some of the interruptible customers have a degree of fuel switching ability. This is the case for the three large power stations (Avedøre II, H.C. Ørsted Power Station and Skærbæk Power Station) which are directly connected to the transmission grid. All three plants have the ability to use oil as a backup supply source.

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Estonia

Key data

Table 4.7.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	4.7	4.7	4.8	10.1	10.9	11.8	11.9
Demand (kb/d)	25.4	21.3	25.2	25.6	25.5	26.0	29.4
Motor gasoline	5.7	6.5	6.7	6.4	6.0	6.7	-
Gas/diesel oil	7.7	8.4	12.8	12.6	13.7	14.7	-
Residual fuel oil	10.1	4.8	3.7	5.1	4.1	2.7	-
Others	1.8	1.5	2.0	1.5	1.6	1.8	-
Net imports (kb/d)	19.4	16.6	20.4	15.5	14.6	14.2	17.5
Import dependency (%)	76.4	78.0	81.0	60.5	57.2	54.6	60
Refining capacity (kb/d)	0.0	0.0	0.0	0.0	0.0	0.0	-
Oil in TPES (%)**	17	14	14	9	9	9	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.7.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	0	0	0	0	0	0	0
Demand (mcm/y)	712	812	979	689	627	670	532
Transformation	345	464	503	420	358	0	-
Industry	305	270	348	142	143	0	-
Residential	58	51	55	67	64	0	-
Others	4	27	73	60	62	0	-
Net imports (mcm/y)	712	812	979	689	627	670	532
Import dependency (%)	100	100	100	100	100	100	100
Natural gas in TPES (%)	11	14	15	10	9	10	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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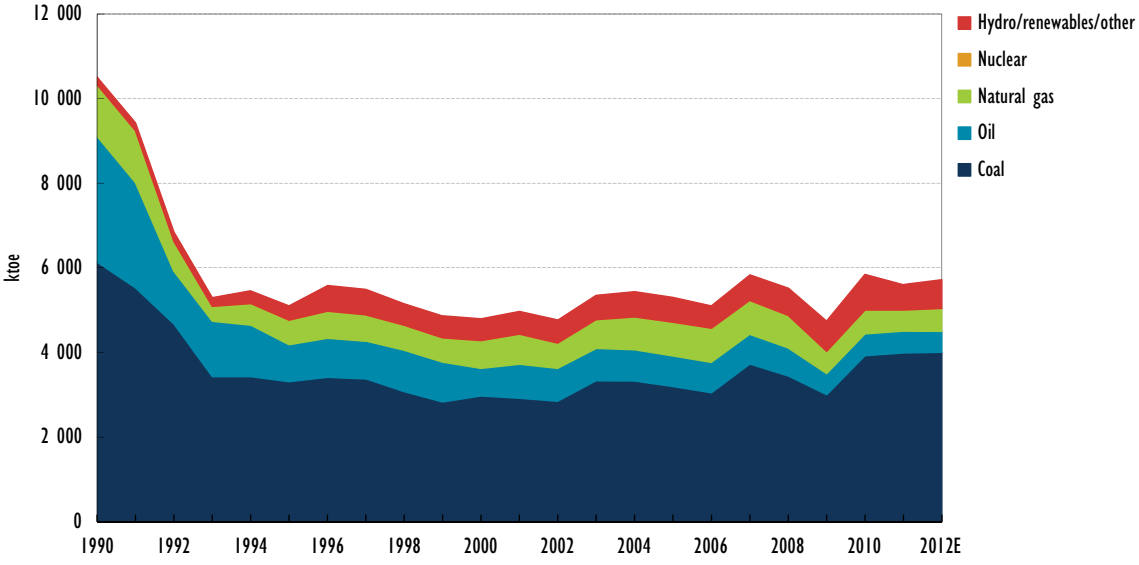
Figure 4.7.1 Total primary energy source (TPES) trend, 1990-2012



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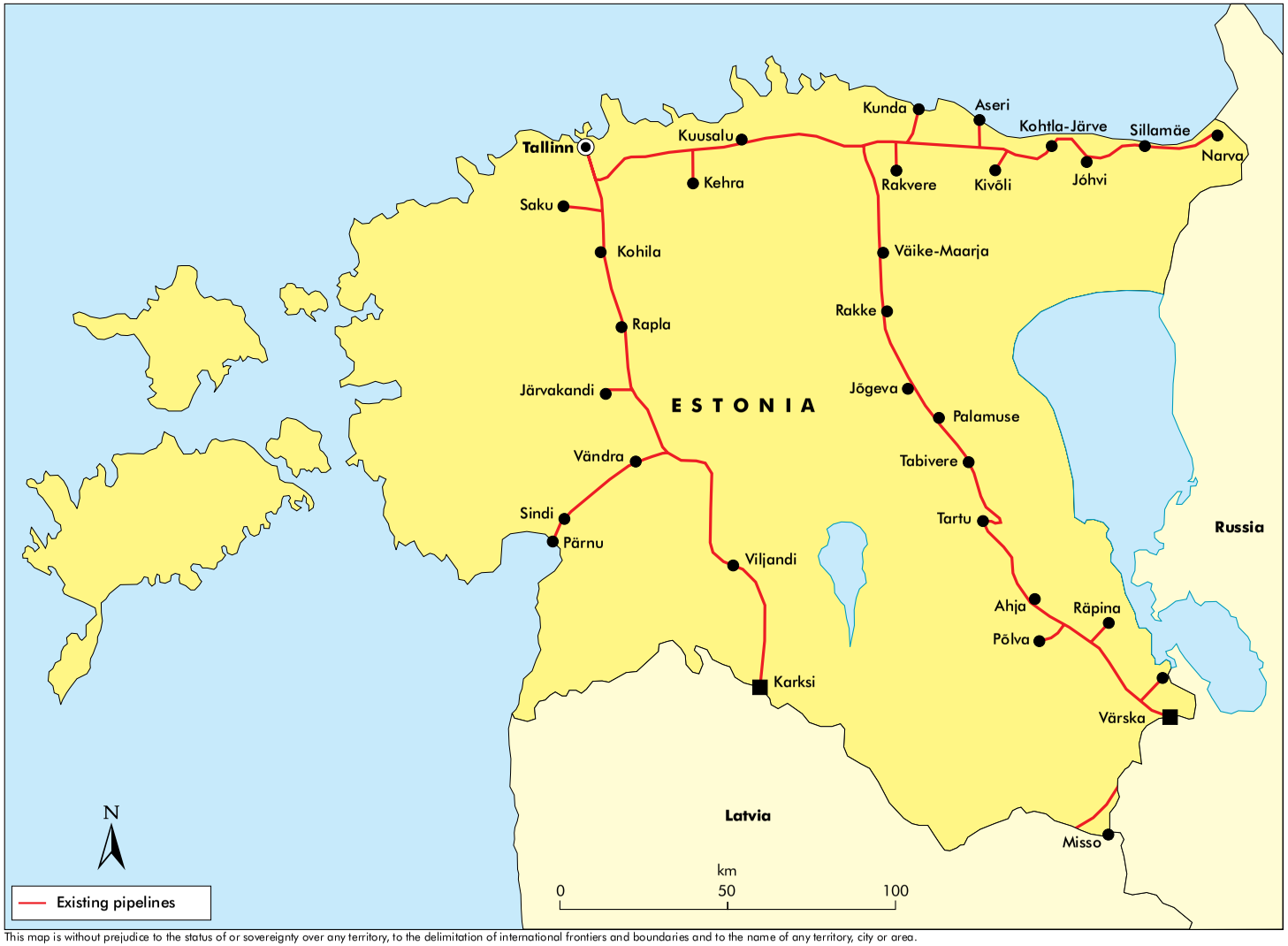
Map 4.7.1 Oil infrastructure of Estonia

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Map 4.7.2 Gas infrastructure of Estonia



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Country overview

Oil and natural gas provide less than a fifth of Estonia's total primary energy supply (TPES); oil accounted for 9% and gas for 10% of TPES in 2012. Estonia has no gas production or oil production. Nevertheless it produces shale oil from oil shale. Shale oil is used as a blending component in bunker fuel to lower sulphur content and as refinery feedstock. Oil shale is also extensively used for power generation and represented around 70% of Estonian TPES in 2011.

Oil consumption in Estonia averaged roughly 26 thousand barrels per day (kb/d) in 2012, concentrated in the transport sector (72%) and primarily in the form of diesel oil. In 2012, some 670 million cubic metres (mcm) of natural gas were consumed in Estonia. A little over half (57%) of the total natural gas usage was by the transformation sector.

The Liquid Fuel Stocks Act (LFA) is the key piece of legislation for oil stock release and other emergency measures for fuel oils. The amendments to the LFA to align the legislation with International Energy Agency (IEA) requirements were approved at the end of October 2013.

In Estonia, roughly 80% of all oil stocks that would be considered for the IEA 90-day calculation were held by the Estonian Oil Stockpiling Agency (OSPA) while the rest were held by industry. These were commercial stocks as Estonia does not place a stockholding obligation on industry. Emergency measures available to the Estonian government in event of an oil supply disruption are limited to the release of stocks from its public stockholding agency. The OSPA, established in 2005, is tasked with establishing, maintaining and holding 90 days of compulsory oil stocks to fulfil Estonia's international obligations. The OSPA is a legal entity governed by private law, whose capital belongs entirely to the state. Shareholder's rights are exercised by the Ministry of Economic Affairs and Communications and represented by the Minister of Economic Affairs and Communications. OSPA stockholding and administration costs are covered through a stockpiling fee paid directly to the OSPA by oil companies. This fee is included in oil prices paid by consumers. The purchasing costs of oil are covered by the state budget by increasing the share capital of the OSPA and by using funds received from the sale of oil stocks.

With no domestic production (except shale oil) or refining, short-term surge production is nonexistent. There is also no real scope for short-term switching away from oil use, as transportation represents nearly three-quarters of all oil consumption. A study to identify Estonian demand restraint measures was carried out in the summer of 2013. Based on this analysis a demand restraint plan that lists all demand restraint measures, including description of risks, costs, and responsibilities was finalised in October 2013. Amendments to the LFA enacted on the 1 of November 2013 now allow Estonia to implement demand restraint plans in case of an emergency.

During the period from May to October, Estonia is supplied with gas directly from the Russian Federation. From November to April, gas is supplied from the Inčukalns underground storage facility in Latvia. In the event of a gas emergency, Estonia's options are very limited as it imports only Russian gas, either directly or indirectly through Latvia. Estonia has recently evaluated its standing with regards to the N-1 standard of the European regulation (Regulation 994/2010), which is designed to test a country's ability to cope if its most important piece of infrastructure is disabled. Estonia fared rather poorly but has now analysed this from a regional perspective, including the other Baltic States, and as a whole the Baltics do meet the standard. There are ongoing regional discussions to build a liquefied natural gas (LNG) terminal; once this is realised, together with the unbundling of gas in Estonia they can help strengthen Estonia's security of supply.

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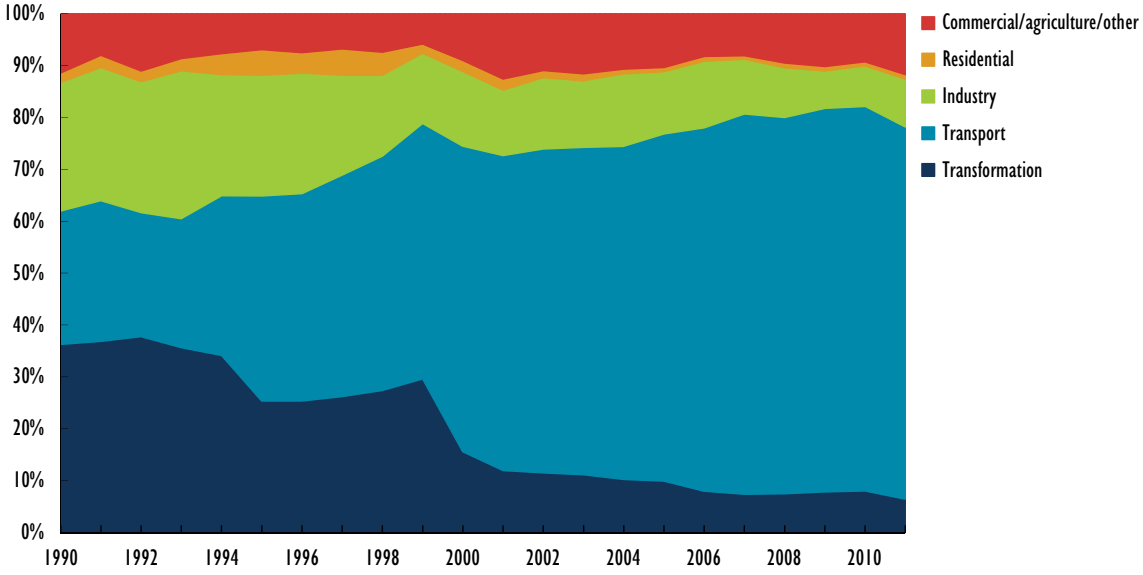
Oil

Market features and key issues

Domestic oil production

Estonia holds significant reserves of oil shale and has an almost century-long history of using this resource for its energy needs. Its oil shale extraction industry is the most developed in the world. Estonia has been generating electricity from oil shale since 1924. Oil shale represented 70% of Estonian TPES in 2011 (for power generation). Estonia also produces shale oil from oil shale, which is used as a blending component in bunker fuel to lower sulphur content and as refinery feedstock. In 2012, shale oil production amounted to 11.8 kb/d. With the current high prices for crude oil and electricity in Europe, the production of shale oil/liquid fuels from oil shale is more profitable than using it for power generation. Therefore shale oil producers aim to increase production considerably by 2015. Development plans, submitted by the producers, suggest an increase in the volume of shale oil production by a factor of 2.6 by the end of the decade compared to 2011 levels.

Figure 4.7.2 Oil consumption by sector, 1990-2011



Oil demand

Oil demand in Estonia declined sharply from 1990 to the end of the decade, as the consumption of heavy fuel oil, which accounted for over 50% of demand, decreased significantly. Since then oil demand has remained relatively stable averaging 25 kb/d since 1997. In 2000, Estonian oil demand sank to its lowest level in the last 15 years, recording 21 kb/d. Conversely, in 2007, before the start of the financial crisis, consumption of oil products reached its highest level (29 kb/d). In 2012, Estonian oil demand stood at 26 kb/d and is likely to increase moderately in the coming years, reaching 29 kb/d by 2018.

Diesel demand has been increasing steadily since the late 1990s. In 2000, it represented 19% of demand and reached 34% in 2012. At present, it is the only oil product registering growth.

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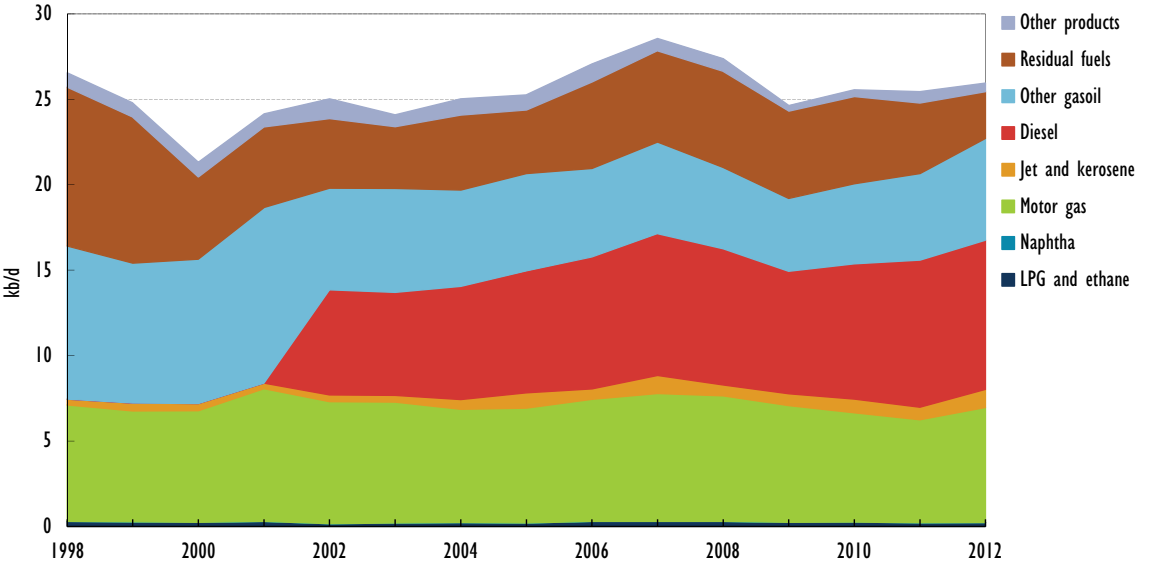
Demand for other gasoil has averaged 5 kb/d in the last 12 years. In 2012, it represented 17% of oil demand in Estonia. Its consumption is also expected to continue rising, albeit very moderately. Combined gas/diesel oil represents the bulk of Estonian demand, currently accounting for 57% of demand.

The share of motor gasoline in oil consumption has declined considerably since 2000. In 2000, it represented 33% of oil demand, while in 2012 this figure was 26%; this is partly the result of the progressive dieselisation of the vehicle fleet as in other European countries.

The demand for residual fuels has averaged 5 kb/d since the turn of the century and currently accounts for 7 kb/d.

Figure 4.7.3 Oil demand by product, 1998-2012



Imports/exports and import dependency

Most oil products consumed in Estonia are imported and originate from refineries located in neighbouring countries, namely Lithuania and Finland. In 2011, Lithuania provided 45% of Estonia's total oil imports, while other countries of the former Soviet Union (FSU) and Finland were the source of 15% and 20%, respectively. It is worth noting that Estonia has reduced its reliance on imports from Russia over the last few years. In 2006, it imported about 46% of its oil from Russia (about 11 kb/d). Since then imports have been reduced significantly reaching only 1 kb/d in 2011.

Although Estonia covers the majority of its demand with imported oil products from neighbouring countries, because it exports most of its shale oil, it reduces its net-import dependence, and therefore the amount of oil it would need to hold to fulfil the IEA 90-day net-import obligation. Based on full-year data from 2012, Estonia's import dependence is estimated at 59%.

There were plans in 2013 to produce diesel from oil shale. These plans would see Estonia producing up to 34 kb/d after 2017, or 6 kb/d more than the current oil demand. Nevertheless, because of the uncertainty surrounding the European Union's Fuel Quality Directive (Directive 98/70/EC), these plans have been put on hold.

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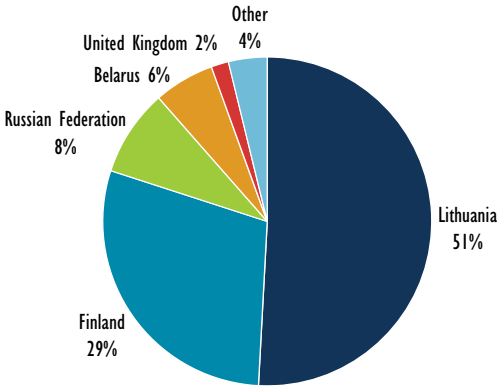
Figure 4.7.4 Oil products imports by origin, 1973-2012



Oil company operations

Estonia's liquid fuels market is unregulated and competitive. There are ten oil importers in the market. The wholesale market is dominated by three players: Orlen, Statoil and Neste Eesti. Together they import about 85% of all oil products. At the retail level, the market is characterised by a large number of service stations in proportion to the size of the country. There are around 500 filling stations (on average only 3 500 citizens per station compared to the European Union average of 5 000); 128 of these are unstaffed. The five largest operators are Alexela, Statoil, Neste, Olerex and Lukoil, which together operate 65% of all stations. The remaining filling stations are either family owned or operated by small retailers, many of them unstaffed. Statoil has the largest share of the retail market (26.4%), followed by Neste (23.5%), Alexela (14.5%), Olerex (14%) and Lukoil (9.6%). Small stations, representing 35% of retail outlets, account for only 12% of the market.

Oil supply infrastructure

Refining

Although there is no crude oil production in Estonia, and it has no refineries, plans were developed for two refineries in the coming years to further refine shale oil for the production of transportation fuels. However, because of uncertainties regarding the Fuel Quality Directive, these plans have been put on hold.

Ports and pipelines

Most fuels are imported by rail from the Mažeikiu refinery in Lithuania (Orlen Lietuva), which is the only refinery in the Baltic States, or by ship from Finland (the Neste refinery in Porvoo). Fuels are distributed throughout the country by tanker trucks. Estonia has no international oil pipeline connections and remains an export route for Russian oil products (mainly heavy fuel oil), although trade through Estonia has been declining since 2007.

Estonia's main oil terminals are located in Tallinn, Muuga and Paldiski. The country relies heavily on its numerous ports and railways to transport products. The most important ports handling oil products are: the Port of Tallinn which handles petroleum products mainly at the Muuga harbour (although to a lesser extent also at Paldiski South and Paljassaare Harbours); the Port of Sillamäe, which is the most easterly port in the European Union; the port of Miiduranna; and the port of Kopli. All are equipped with

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loading and storage facilities. Some of these oil terminals also have a developed rail infrastructure connected to the main Estonian rail network.

The oil terminal operators of the Port of Tallinn provide storage services for petroleum and petroleum products, consolidation of large consignments and blending services. The Port of Tallinn is used to trans-ship oil products from Russia, Belarus and Kazakhstan to various destinations around Europe (primarily the Netherlands). In 2010, the port handled 25.8 million tonnes (Mt) of oil products (mostly heavy fuel oil) or 500 kb/d on average. It has the capacity to ship up to 40 Mt of liquid fuels a year.

Storage capacity

Estonia has extensive storage capacity because of its very active oil transit business. Since May 2007 oil transit has significantly decreased, freeing up storage space and thus making space for more Estonian stocks to be held in Estonia. In 2006 the oil transit volume per year exceeded the volume of Estonia's 90-days oil stocks requirement approximately 137-fold.

The Port of Tallinn has a total storage capacity of 2 mcm for oil products, mainly diesel and gasoline. Storage capacity along the Estonian coast is a little over 3 mcm, or roughly 20 million barrels – this figure includes all major Estonian ports. Among the other Estonian ports, the Port of Sillamäe has the largest capacity with 0.5 mcm for the storage of oil products.

Estonia also has storage facilities inland. These storage sites are concentrated in three main areas: Maardu (close to Tallinn), Viljandi and Tartu. Combined, they have a total capacity of about 130 000 m^3, mostly dedicated to the storage of gasoline and diesel.

In total, Estonia has considerable storage capacity with over 3.2 mcm capacity, most of it concentrated along the coast and more specifically in the Port of Tallinn.

Decision-making structure

The most effective emergency response instrument during an oil supply disruption for Estonia would be the release of its public emergency stocks. The government, on the advice of the Minister of Economic Affairs and Communications, decides on the stockdraw. The decision is approved beforehand by the crisis management committee of the government. Amendments to the Liquid Fuel Stocks Act (LFA), which strengthen Estonia's emergency policies and procedures, entered into force on the 1 November 2013. These amendments envisage the creation of a national emergency strategy organisation (NESO) to deal more effectively with oil supply crises; it also contains some enhancements to current practices. The amendments allow for the rapid deployment of demand restraint plans. The enhancements align Estonia with IEA accession requirements.

The OSPA, a public stockholding agency, established in 2005 to fulfil Estonia's international obligations, is tasked with establishing, maintaining and holding 90 days of compulsory oil stocks. OSPA stockholding and administration costs are covered through a stockpiling fee paid directly to the OSPA by oil companies. This fee is included in oil prices paid by consumers. The purchasing costs of oil are provided by the government by increasing the share capital of the OSPA and by using funds received from the sale of oil stocks.

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Stockholding structure

All the stocks are established and held by the state company, the OSPA (the Agency). Estonia does not place a stockholding obligation on industry. It is worth noting that the District Heating Act requires district energy suppliers with projected annual heat production above 500 000 megawatt hours (MWh) to hold liquid fuel reserves amounting to three days of consumption. At the time of writing, only one company has this obligation.

Crude or products

All the stocks are in the form of final products in four categories: diesel, gasoline, jet and heavy fuel oil. No crude oil is stockpiled. In February 2013, the Agency held around 235 000 tonnes of petroleum products in stock. At the end of 2012, according to IEA net-import calculations, the Agency held 189 days of net imports. Middle distillates account for about 65% of all oil stocks held by the OSPA, while motor gasoline accounts for 34%.

Location and availability

All the storage sites which are above-ground facilities, most in sea terminals, are rented by the Agency. Roughly half of the stocks are held under bilateral agreements in foreign countries: Denmark, Finland and Sweden. The stocks are held separately from the industry's commercial stocks.

Monitoring and non–compliance

The OSPA inspects the stocks on a regular basis (including inspections without advance notification). For that purpose independent inspectors are contracted both in Estonia and abroad. The inspections consist of volume audits and quality analyses. Any violations detected by storage operators can be severely penalised, with the storage agreement foreseeing heavy financial penalties as well as options for contract termination.

Stock drawdown and timeframe

According to the national crisis management regulations, the decision-making process shall not take more than 72 hours. Most of the communication can be managed on line without a need for on-site meetings.

The stocks are sold at the market price at the time of delivery. The time estimated for deliveries from overseas is no more than 27 days. The transportation of the stocks to Estonia is to be arranged by the OSPA.

In case of ticket agreements stocks are sold to the market players in the same way as the stocks owned by the OSPA. However, in the case of tickets, the Agency buys the stocks from the ticket seller and then sells these stocks to the market players. In cases where the market player is also the ticket seller, then it has the right to use the stocks in the volume indicated in the sales offer.

Financing and fees

Every year, the management board calculates the new stockholding obligation based on the latest oil consumption/net-import data. The fulfilment of the obligation is analysed in every year's budget. It is then approved by the supervisory board of the OSPA. Estonia had a transitional period for the establishment of oil stock between 2003 and 2009; 1 January 2010 was the target date for reaching the 90 days of oil stocks. The 90 days

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were based on oil consumption in 2008. Because of the decrease in oil consumption after 2008, the total stock level was (and still is) above 100 days.

Procurement of stocks is financed from the state budget and is accounted for as share capital of the Agency. The operation and maintenance costs are financed from the oil stockholding fee, which is collected from the oil market players.

In 2012 the stockholding costs were in range of EUR 5.7 million. The average storage fee was approximately EUR 15/m³/year. This figure relates to the final products stored above ground.

Other measures

Demand restraint

In the event of international supply disruptions, Estonia is able to reduce the consumption of motor fuel by 7% to 10% through demand restraint measures, depending on the nature of the interruption of supply, in addition to the reduction that would be caused by price increases. The programme defines the savings potential, costs and target groups of different measures.

Estonia's demand restraint programme identifies mainly "soft" measures related to raising awareness and changing consumption choices and regulatory measures that would not entail a limitation of human rights and changes in the existing legislation: reduction of the speed limit, promotion of public transport and increasing the frequency of public transport, promotion of sustainable driving methods and encouraging carpooling.

Other

With no domestic production or refining, short-term surge production is nonexistent in Estonia.

Gas

Market features and key issues

Gas production and reserves

Estonia is not a gas producer and is fully dependent on imported gas from Russia, which is supplied by pipelines directly from Russia or from storage facilities in Latvia.

Gas demand

During the period from May to October, Estonia is supplied with gas directly from Russia. From November to April, gas is supplied from the Inčukalns underground storage facility in Latvia.

In 2011 Estonia consumed about 627 mcm of gas, one of the lowest levels of consumption registered in Estonia since the mid-1990s (estimates for 2012 suggest consumption reached 670 mcm that year). More than half of Estonian gas consumption is used in the transformation sector, primarily for heat generation in Estonia. The use of natural gas for electricity generation is extremely modest at only 2% of total gas consumption.

Between 2004 and 2008 gas consumption was above 900 mcm a year, but declined sharply afterwards. This was partly owing to the general economic downturn, but

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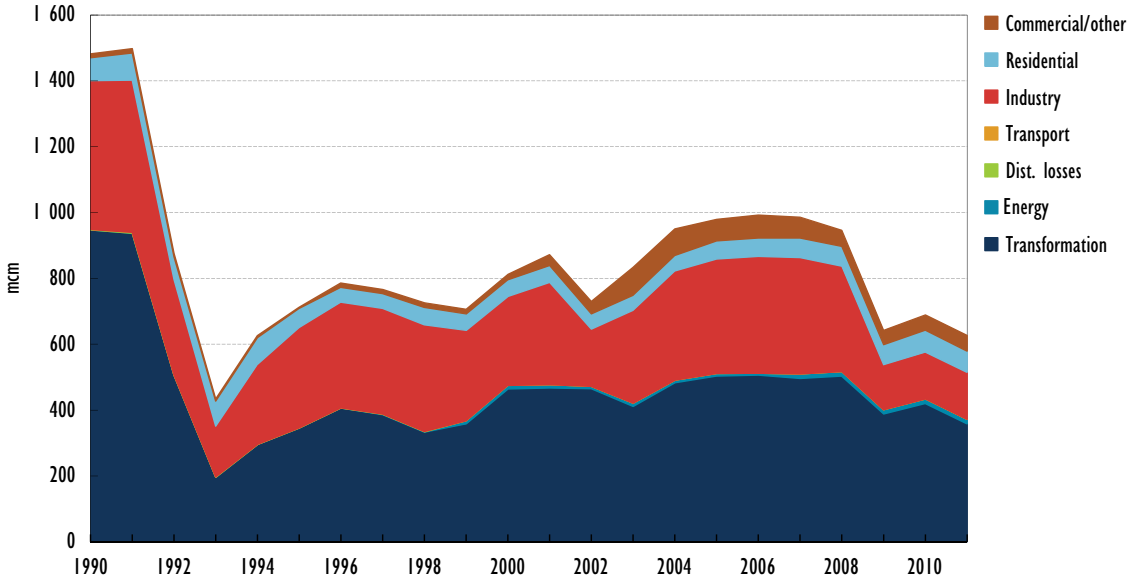
the greatest impact was the cessation of economic activity of the fertiliser producer Nitrofert AS in February 2009. In 2007 the share of industrial consumption was 36% of the total, while in 2009 this figure plummeted to 21%. Nitrofert represented close to 20% of the total consumption of natural gas in Estonia. Nitrofert resumed operations in December 2012, although it is still unclear whether it will scale up its ammonia and urea production to pre-2009 levels.

Figure 4.7.6 Natural gas consumption by sector 1990-2011



As Estonian gas consumption is primarily destined for heat generation, Estonia uses up to five times more gas in winter than in summer. During the peak winter months, demand can rise to over 7.0 mcm/day, which is greater than the maximum drawdown capacity from the Inčukalns gas storage facility.

The maximum daily consumption of gas for heating in the past 20 years was in the winter of 2006 with 6.7 mcm/day. The maximum daily gas consumption in spring (April) 2010 was 2.147 mcm/d, and the minimum daily consumption of 0.5 mcm/d was in July 2010. In February 2012, the daily peak consumption reached 5.7 mcm, representing the highest daily consumption for the last five years.

Gas import dependency

Estonia imports the totality of its gas from Russia. Although Estonian legislation permits any market participant to import gas, Eesti Gas is essentially the only gas importer and trader/reseller in the country.

The Estonian government is exploring the possibilities for increasing the reliability of natural gas supply and is co-operating closely with regional governments and key energy stakeholders in promoting regional market integration with neighbouring EU member states.

Gas company operations

The Estonian gas market has been open since 1 July 2007; this was essentially a market opening in name only and there is no competition in the gas market. The vertically integrated operator Eesti Gaas is a dominant market player for both wholesale and retail

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markets. Eesti Gaas established the independent system operator (ISO) EG Võrguteenus, which leases the Eesti Gaas assets necessary for the provision of transmission services. Eesti Gaas is the only wholesaler in Estonia and imports gas from a single supplier (Gazprom) under a long-term contract. Supply volumes of natural gas in the current contract represent up to 7 mcm/day until the end of 2015.

Estonia, along with Latvia, Lithuania and Finland, was exempt from the ownership unbundling requirements under EU Directive 2009/73/EC until it is directly linked to the interconnected systems of the EU member states. The Estonian parliament, however, made the decision not to apply this exemption, and will require ownership unbundling of the gas transmission network from supply and distribution by 1 January 2015.

Gas supply infrastructure

Ports and pipelines

Estonia has operational interconnections with the Russian natural gas network in Värska, and with Latvia in Karksi with a maximum capacity of 11 mcm/day. The Estonian gas system has another interconnection with Russia in Narva (in the northeast), which has been closed because of limits in maximum pressure on the Estonian border and is used only by special agreement with Gazprom. According to a Gazprom Transgaz statement in late autumn 2012, reconstruction work has been carried out in Russia, which allows an increase of gas pressure in pipes up to 29 bar, making it also possible to use gas through the Narva interconnection at a maximum of 3 mcm/d throughout the winter period.

The gas network in Estonia is 2 314 km long, 878 km used for transmission and 1 436 km for gas distribution. There are three gas-metering stations in Värska (from Russia with 4 mcm/day at 40 bar inlet pressure), Karksi (from Latvia) and Misso (see transit section below) and 36 gas distribution stations. The system is owned by Eesti Gaas, and operated by EG Võrguteenus, which provides transmission and distribution services, as well as operating the gas metering systems on the Estonian border.

EU Regulation no. 994/2010, which covers the security of natural gas supply, requires maintaining gas supplies in the event of disruption of the single largest gas infrastructure, i.e. the fulfilment of the N-1 criterion, including events of peak demand. The individual risk assessment carried out by Estonia showed that Estonia would not fulfil the standard; it scored 60%. Nevertheless, in a regional risk assessment carried out in collaboration with Lithuania and Latvia, when all three countries were considered as a whole in the event of a disruption of the single largest gas supply infrastructure – the natural gas supply line from Minsk to Vilnius – the infrastructure standard N-1 scored 129.73%.

To secure a continuous energy supply, the Estonian National Development Plan of the Energy Sector until 2020 foresees the need to diversify the use of energy sources and to construct new natural gas and LNG infrastructures in order to fulfil the N-1 requirement.

As a net importer of natural gas from a single source, Estonia is working closely with other governments in the region to diversify its sources of gas supply. Projects currently under negotiation include an LNG terminal in the Gulf of Finland. The new connections and terminal could cover the potentially greater regional demand of11 bcm/year by 2030, with a share of almost 6 bcm/year of the Baltic States' demand.

Storage

Estonia has no domestic gas storage facilities. It uses the Inčukalns underground gas storage facility in Latvia, which supplies gas to major consumers in Estonia, Latvia, Lithuania and northwest Russia, primarily for heat generation.

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Inčukalns is the only functioning natural gas underground storage facility in the Baltic States. It has a total capacity of 4.47 bcm; about 2.32 bcm of this is active at present. It has a maximum drawdown capacity of about 7 mcm/d. According to the owner of Inčukalns, it is possible to increase its active capacity to 3.2 bcm.

The daily quantities of gas delivered from Inčukalns depend on the season and technical limitations. Increase in demand because of extremely low outside temperatures affects supplies to large consumers of Inčukalns gas storage not only in Estonia but also in Latvia, Lithuania and Russia. The most critical period for Estonian gas supply from the Inčukalns gas storage is spring (April), when the drop in gas volumes creates lower pressure on the Estonian border, affecting the delivery of gas.

Emergency policy

Emergency response measures

Estonian legislation states that gas supplies to household customers may not be interrupted or limited during the period from 1 October to 1 May. The same requirement applies to supplies of residential space heating, which can use no fuel other than gas. The only exemption to this rule is in the case of danger to life, health, property or environment or an agreement between parties.

Since 1 July 2008, those district heating companies with an annual estimated production volume of over 500 000 MWh per network area are legally obliged to hold a supply of alternative heating fuel for three days, in order to secure an uninterrupted heat supply. From 2012 Tallinna Küte AS has been obliged to keep liquid fuel reserves. Until 2012 the same ruling also applied to Eesti Energia's Iru power plant, but under the new contract its projected production volume fell below 500 000 MWh; it is therefore no longer required to hold alternative fuel reserves.

The requirements for the quality of gas supply were established by amendments to the Natural Gas Act at the beginning of 2007. The amendments set a limit on sequential supply disruptions, which should not exceed 72 hours, as well as an annual total duration of disruptions which may not be longer than 130 hours in total.

According to data from EG Võrguteenus in 2011 there were 708 interruptions in total: 376 were planned during works, 255 were at the request of the sales department of Eesti Gaas, while 77 cases were emergency disruptions. None of the disruptions lasted over 12 hours.

As part of EU Regulation EU no 994/2010, Estonia prepared the *Risk Assessment of Estonian Gas Supply* (2010), and in co-operation with Latvia and Lithuania, the *Joint Risk Assessment of Gas Supply of Estonia, Latvia and Lithuania* (2012). The joint risk assessment provides an outlook for the regional energy mix and the functioning of the regional gas market. It examines the possibilities for physical gas flows, assesses the existing physical natural gas infrastructure and the political and administrative risks.

It examines different risk scenarios, risk impact and response scenarios, establishing a supply disruption risk matrix, and defines gas supply disruption risk mitigation measures which are part of the Preventive Action Plan.

The Estonian Preventive Action Plan and the Emergency Plan as part of the EU regulation was enforced by a Ministerial Decree in June 2013. Estonia is conducting consultations on the joint plans at the regional level with Latvia and Lithuania.

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Finland

Key data

Table 4.8.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Demand (kb/d)	225.5	215.0	219.6	215.9	207.7	196.5	178.7
Motor gasoline	46.0	41.3	43.5	39.0	37.6	36.9	-
Gas/diesel oil	85.8	87.3	84.8	88.1	84.5	85.8	-
Residual fuel oil	41.9	35.3	34.3	24.5	20.5	16.9	-
Others	51.9	51.2	57.0	64.4	65.1	56.9	-
Net imports (kb/d)	225.5	215.0	219.6	215.9	207.7	196.5	178.7
Import dependency (%)	100	100	100	100	100	100	100
Refining capacity (kb/d)	241.0	200.0	251.8	257.1	257.1	257.1	-
Oil in TPES (%)**	34	29	30	26	26	25	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.8.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	0	0	0	0	0	0	0
Demand (mcm/y)	2 681	4 199	4 435	4 700	4 118	3 671	3 439
Transformation	1 199	2 759	3 078	3 047	2 498	0	-
Industry	1 156	1 060	952	1 171	1 128	0	-
Residential	34	28	37	59	39	0	-
Others	292	352	368	423	453	0	-
Net imports (mcm/y)	2 681	4 199	4 435	4 700	4 118	3 671	3 439
Import dependency (%)	100	100	100	100	100	100	100
Natural gas in TPES (%)	8	11	11	11	10	9	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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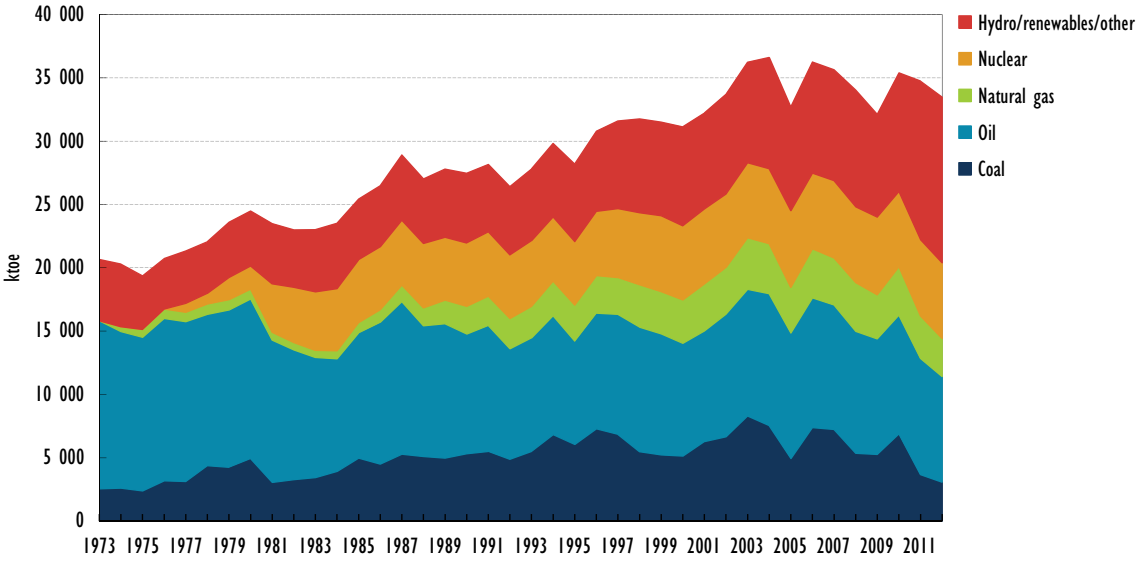
Figure 4.8.1 Total primary energy source (TPES) trend, 1973-2012



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Map 4.8.1 Oil infrastructure of Finland

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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Map 4.8.2 Gas infrastructure of Finland

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Country overview

Oil has been a main energy source in Finland, accounting for some 25% of the country's total primary energy supply (TPES) in 2012. Finland's oil demand slightly increased from 215 thousand barrels per day (kb/d) in 2000 to 224 kb/d in 2007, and then decreased to 197 kb/d in 2012. The transport sector accounted for almost half of total oil consumption in 2011.

As Finland has no domestic oil production, it is entirely dependent upon crude oil imports. In 2012, its oil imports were around 328 kb/d, consisting of 206 kb/d of crude oil, 24 kb/d of natural gas liquids (NGLs) and feedstock, and 97 kb/d of refined products. Around 89% of the total crude oil imports came from the Russian Federation. In the country, there are two refineries with a total crude distillation capacity of around 265 kb/d. Finland was a net exporter of refined products, exporting around 163 kb/d of refined products in 2012.

Finland meets its stockholding obligation to the International Energy Agency (IEA) by holding government stocks and by placing a minimum stockholding obligation on industry. Under the relevant acts, the National Emergency Supply Agency (NESA) manages the public oil emergency reserves. Oil importers are obliged to hold at least two months of stocks based on an average of their imports from the previous year.

The use of emergency oil stocks is central to Finland's emergency response policy, which can be complemented by demand restraint measures. Finland held 38 million barrels (mb) of oil stocks for oil emergencies at the end of April 2013.

The share of natural gas in the country's TPES stood at 9% in 2012. Finland's gas demand increased from 0.5 billion cubic metres (bcm) in 1974 to 5 bcm in 2005, and has steadily decreased to 3.7 bcm (10.1 mcm/d) in 2012. Not having any domestic natural gas production, Finnish gas demand is entirely met by imports from Russia supplied via a twin pipeline connection.

Key elements in Finland's overall gas security policy are compulsory stocks in the form of oil products for fuel switching, control of excess supply and cut back of contractual supplies. The gas importer, gas plants and municipal users consuming above a certain amount of gas are each obliged to hold alternative fuel stocks corresponding to three month's natural gas import/consumption. NESA also holds alternative fuel stocks for gas disruptions, and decides the amount of its stocks in consideration of the government's objective to have stocks of imported fuels equivalent to five months' consumption of all imported fuels. This covers stocks for industrial use on which there is no stockholding obligation. Substitute fuels for gas are light fuel oil, heavy fuel oil and propane gas.

The transmission system operator (TSO), Gasum Oy, is responsible for assuring gas supplies to protected customers who can only use gas by providing air-mixed propane gas. In case of a natural gas disruption, liquefied petroleum gas (LPG) stocks are also planned for use in the Porvoo refinery, one of the largest consumers of natural gas in the country. Small amounts of liquefied natural gas (LNG) stocks that have been domestically liquefied can also be made available during gas disruptions.

Oil

Market features and key issues

Domestic oil production

Finland has no domestic production of crude oil and its oil demand is fully covered by imports.

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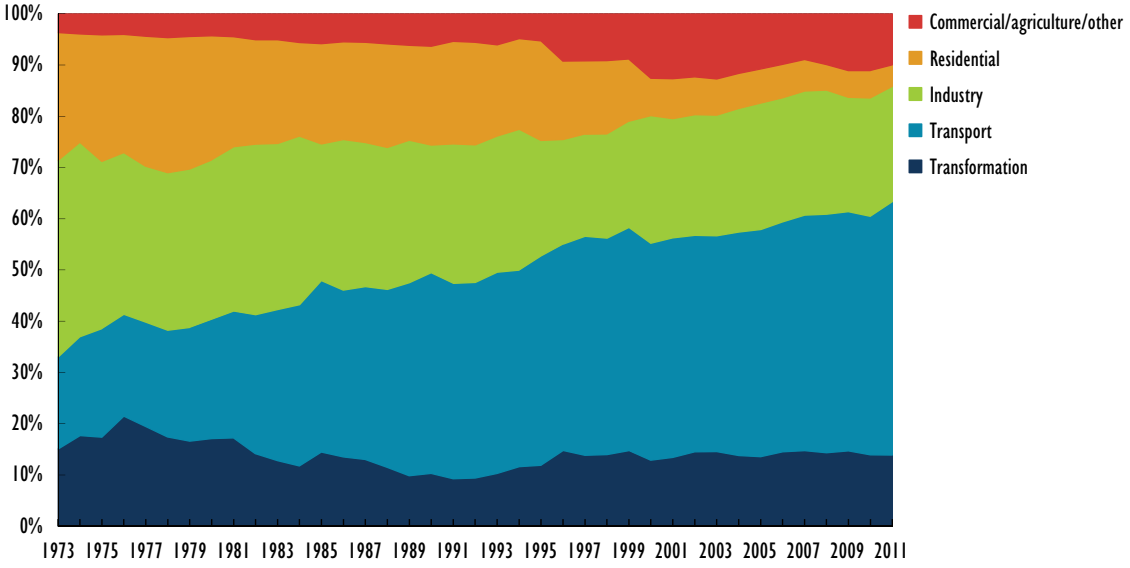
Oil demand

The country's oil demand increased slightly from 215 kb/d in 2000 to 224 kb/d in 2007, and then decreased to 197 kb/d in 2012. Total oil demand is expected to decrease to some 179 kb/d in 2018.

In 2011, almost half of Finnish total oil demand was consumed by the transport sector; whilstthe industry sector accounted for 23% and the transformation/energy sector for 14%.

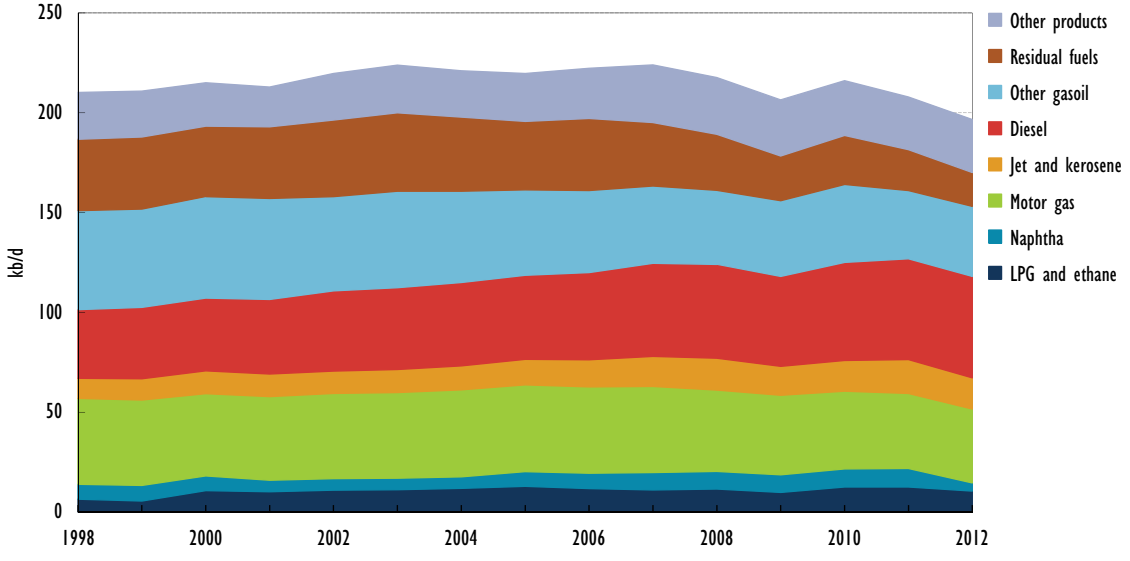
Figure 4.8.2 Oil consumption by sector, 1973-2011



The demand for diesel has increased by 24% between 2003 and 2012, whereas demand for gasoline has decreased by 14% over the same period. Demand for heating oil/other gasoil and residential fuels dropped significantly by 27% and 57% respectively.

In Finland, 6% of transport fuels should be bio-components (in terms of energy content) whose raw materials are mostly imported.

Figure 4.8.3 Oil demand by product, 1998-2012



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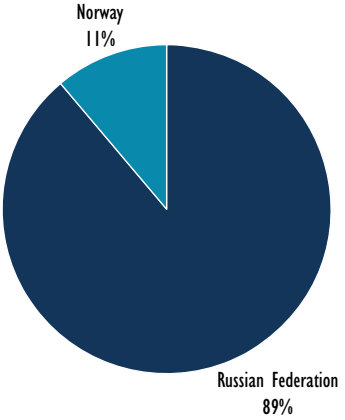
Imports/exports and import dependency

In 2012, Finland's oil imports were some 328 kb/d, consisting of about 206 kb/d of crude oil, 24 kb/d of NGLs and feedstock and 97 kb/d of refined products.

Finland is highly dependent on Russia as a source for its crude oil imports, which accounted for 89% of total crude oil imports in 2012, with the rest imported from Norway. The import dependency on Russian crude oil significantly increased from 43% of total crude oil imports in 2000 to 89% in 2012, with a compound growth rate of around 7%.

Figure 4.8.4 Crude oil imports by origin, 2012



In 2012, refined product imports came from Russia (52%), Sweden (11%), Kazakhstan (8%) the Netherlands (6%) and Korea (4%). However, in the same year Finland was a net exporting country of refined products, exporting around 163 kb/d of refined products, 26% of which was shipped to Sweden.

Oil company operations

Neste Oil Oy, a majority state-owned company, is a key player in the domestic market and is the only crude importer owning both refineries in Finland. In the Finnish retail market, the share of Neste Oil Oy was around 33%, followed by Teboil (25%), ST1 (12%) and ABC (11%). In addition, North European Oil Trade Oy (NEOT) – owned by SOK and St1 Oy – acts as a wholesale company which deals with the procurement and logistics of oil products for certain retail companies.

Oil supply infrastructure

Refining

The two refineries in Finland, with a total crude distillation capacity of around 265 kb/d are the Porvoo refinery (206 kb/d) and the Naantali refinery (58.5 kb/d). In 2011, total crude throughputs averaged 231 kb/d, which indicates that the overall capacity utilisation rate was over 85%. In 2012, the refined product output from the two domestic refineries totalled some 291 kb/d. The composition of production from these refineries was gas/diesel oil (47%), gasoline (33%), residual fuel oil (8%) and other middle distillates (4%).

With the exception of gasoline, gas/diesel oil and residual fuels, domestic refinery production was insufficient to meet demand in the country. In 2012, domestic production of jet and kerosene was able to meet 78% of domestic demand, requiring

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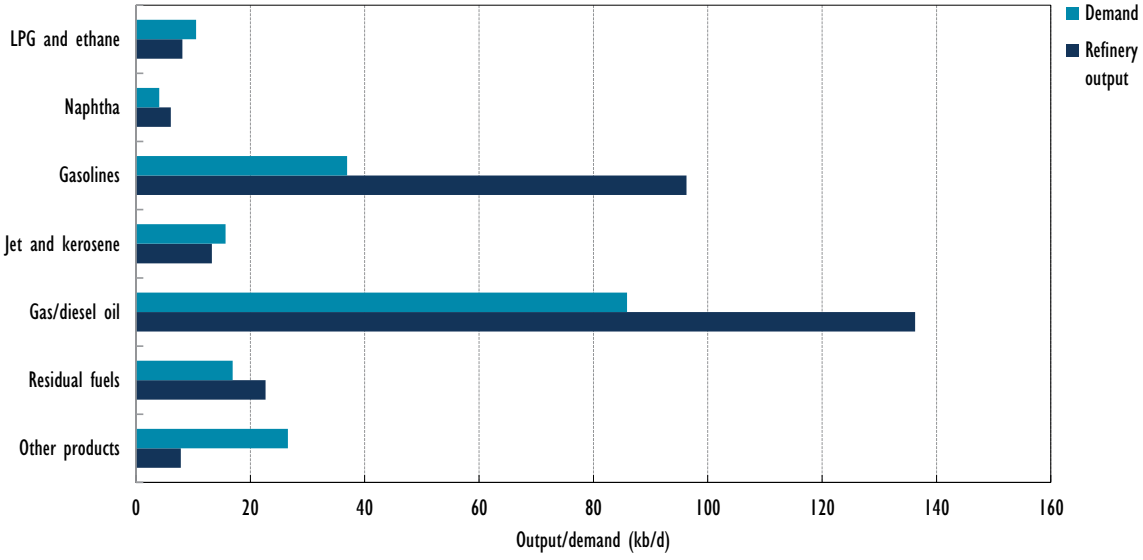
imports to meet the remaining share. However, 40% of the refined oil product outputs, including gasoline and diesel oil, were exported in 2012.

Figure 4.8.5 Refinery output vs. demand, 2012



Ports and pipelines

Finland has no cross-border oil pipelines or domestic oil pipelines. Imports of crude oil and petroleum products are mainly undertaken by tanker fleets, rail tanks and trucks. Of these transport routes, in 2011 over 91% of the feedstock used at Neste Oil's refineries was supplied by sea, 7% by rail and the rest mainly by road; 70% of products to Neste Oil's domestic customers was shipped by sea, 19% by road and the rest by rail.

Crude oils and refined products are imported through six main oil import terminals. Of these, only Porvoo and Naantali terminals, owned by Neste Oil, can import crude oils with a total crude oil import capacity of 19 million tonnes (Mt) per year (some 385 kb/d): 304 kb/d in Porvoo and 81 kb/d in Naantali. Russian crude oil is imported from the nearby Russian oil port of Primorsk, which is located 147 nautical miles from the Porvoo terminal.

The importing and exporting capacity of the Porvoo and Naantali terminals together is 18 Mt/year (some 300 kb/d based on the share of product imports): 15 Mt (250 kb/d) in Porvoo and 3 Mt (50 kb/d) per year in Naantali.

Storage capacity

Finland has a total storage capacity of over 63 mb (10 mcm), mainly in 25 coastal and major inland storage facilities. Major coastal terminals are located at the refineries in Porvoo (44 mb or 7 mcm) and Naantali (6 mb or 1 mcm), and at Inkoo (3.1 mb or 0.5 mcm), Kokkola (2.5 mb or 0.4 mcm), Kemi (1.6 mb or 0.2 mcm) and Hamina (0.6 mb or 0.1 mcm). Around two-thirds of the all storage facilities are in the form of underground rock cavern storage.

While the major storage facilities are owned mostly by the industry, the public stockholding agency NESA owns more than half of the storage capacity necessary for storing public stocks.

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Decision-making structure

The Department of Energy in the Ministry of Employment and the Economy is responsible for general energy issues related to the security of supply in normal times as well as during supply disruptions. The department forms the core of the Finnish national emergency strategy organisation (NESO).

The NESO also includes personnel from the NESA, the Ministry of Transport and Communication, and industry. The Security of Supply Act (1992) provides the legal basis for co-operation between NESA and the industry, which is made through a pooling system such as the Oil Pool and Power and District Heat Pool. The Oil Pool updates contingency plans as well as general guidelines for a disruption, and conducts training and seminars.

During an emergency, the Council of State will make a decision to release public stocks, based on a proposal by the Ministry of Employment and the Economy. Obligated industry oil stocks may be released upon NESA's approval in case a shortage of oil could endanger the operations of the holder of the compulsory stocks.

Stocks

Stockholding structure

Finland meets its stockholding obligation to the IEA by holding government stocks and by placing a minimum stockholding obligation on industry. NESA manages public oil emergency reserves under the Act on the Security of Supply (1390/1992).

According to the emergency reserve target set by the Government Decision on the Objectives of Security of Supply issued on 21 August 2008, the country should hold a total of five months' stocks of imported fuel consumption of oil, natural gas and coal. Even though there is no official objective for individual fuels, the government makes efforts to maintain stocks for each fuel at close to five months of consumption.

While oil importers are required to maintain compulsory oil stocks corresponding to two months' imports based on the average of the previous year, NESA holds the public stocks corresponding to the remaining balance of the stockholding target. The stockpiling obligation applies to the imports of crude oil, other condensates for refineries, diesel oil, light fuel oil, gasoline (motor and aviation) and jet fuel. Based on the Act on the Compulsory Stockholding of Imported Fuels (1070/1994), oil importers who annually import less than 39.5 kb (5 000 tonnes) of kerosene/jet fuels, less than 84.5 kb (10 000 tonnes) of motor gasoline and less than 147.5 kb (20 000 tonnes) of crude oil or other products are exempted from the obligation to hold compulsory stocks. NESA is responsible for ensuring the implementation of the oil stockpiling obligations. It is empowered to determine the quantities of oil to be stockpiled on an annual basis and to supervise the compulsory stocks and their use.

Crude or products

At the end of April 2013, Finland held some 38 mb of oil stocks (19 mb of government stocks and 19 mb of industry stocks), equal to 210 days of 2012 net imports (120 days of government stocks and 90 days of industry stocks), to meet its IEA obligations. Middle distillates accounted for 66% of the total public stocks, followed by crude oil (26%) and motor gasoline (6%). In terms of industry stocks, crude oil was the main product held (24%), followed by middle distillates (23%). Compulsory stocks are commingled with commercial and operational stocks.

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A crude oil importer has an obligation to hold stocks in the form of crude. However, it can apply for permission from NESA to substitute up to 50% of this crude oil stock obligation with oil products. Likewise, importers of oil products have an obligation to hold stocks of the same products, but can apply for permission to substitute their obligation to hold a particular product by other finished products. Substitution of oil products by crude oil is not allowed.

Location and availability

Finland has bilateral agreements with Sweden, Denmark, Estonia and Latvia. Although Finnish oil importers may hold up to 20% of stocks in the countries which have concluded bilateral agreement with Finland, as of 2013 no compulsory stocks are held abroad. Public stocks maintained by NESA are not allowed to be held outside the country. Public stocks of crude oil are located in both refineries, although most are stored at the Porvoo refinery.

For the minimum operating requirements, Finnish oil refineries hold 2 weeks of feedstocks and other oil importers hold 10-14 days of product stocks on top of the compulsory stocks.

Monitoring and non-compliance

NESA conducts regular on-site audits to monitor physical availability and the quality of compulsory stocks.

Companies can be fined if they fail to comply with their stock obligations in terms of quality, quantity and location of oil products.

Stock drawdown and timeframe

The Act on the Security of Supply (1390/1992) requires a decision by the Council of State to draw down public stocks during an oil supply disruption. The Council of State will make a decision based on a proposal made by the Energy Department of the Ministry of Employment and the Economy in close co-ordination with the Oil Pool of the Finnish NESO. The amount of drawdown is determined based upon estimates of imports, exports and estimated consumption. The government's decision could be made in two to four days.

Upon receiving the stock release order from the government, NESA would release public stocks to oil refineries, oil companies and major consumers through public tenders. Foreign companies are also allowed to participate in the tendering.

For the industry obligation, NESA may, upon request, authorise industry holders of compulsory stocks to use their obligated stocks if the holder's production or business would be at risk. It is estimated that such a decision could be made in two days. Decisions on how the compulsory stocks should practically be released are made by the stockholder. The government can also temporarily release compulsory industry stocks to meet international commitments such as IEA and EU obligations.

Financing and fees

Public stockpiling costs, including operation and management fees, are financed by a levy called the precautionary stock fee. It is charged on end-user prices of gasoline, diesel, fuel oils, coal, natural gas and electricity. The level of the stock fee is EUR 2.86 per tonne for low-sulphur fuel oil, EUR 6.73 per kilolitre (kL) for motor gasoline, EUR 3.53 per kL for light fuel oil and diesel oil and EUR 2.86 per kL for heavy fuel oil.

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The total annual budget of NESA amounts to around EUR 50 million, around 20% of which is used for stockholding of energy resources.

The Finnish government does not provide financial support for building compulsory industry stocks. All refiners and importers must self-fund the operational costs of meeting emergency requirements. These costs are implicitly passed on to final consumers in market prices.

Other measures

Demand restraint

Demand restraint is considered as a secondary emergency response measure that could complement an oil stock release in Finland. As Finland has abundant amounts of emergency oil stocks, demand restraint measures would only be deployed in case of a long-lasting, severe supply disruption.

Finland's demand restraint measures would range from light-handed measures on a recommendation basis (e.g. lowering of room temperature in space heating and limitations in ventilation and warm water), to heavy-handed measures made by compulsory orders (e.g. lowering of speed limit, lowering of room temperature, limitations in use of cars and rationing of traffic fuels/light and heavy fuel oils in space heating, industrial use and agricultural use).

Measures based on recommendations can be implemented immediately by the authorities responsible, while full operations of compulsory measures require one to three months of preparation.

Plans for fuel rationing have been regularly updated to take account of changes in the Finnish oil market, according to the Act of Security of Supply.

Fuel switching

Short-term fuel switching from oil to other fuels is not regarded as an emergency response measure in Finland, as the ratio of oil used for power generation to Finland's total oil consumption was only 0.6% in 2012. There is little potential to switch away from oil to other fuel sources.

Gas

Market features and key issues

Gas production and reserves

Apart from a small amount of biogas production, Finland has no domestic production of natural gas. With a single gas import link, Finland has been importing all its natural gas from a single source, Russia, since 1974.

Gas demand

Finland's demand for natural gas increased from 0.5 bcm in 1974 to 5 bcm in 2003, and then decreased to 3.7 bcm (10.1 mcm/d) in 2012.

In 2011, the transformation sector was the largest consumer of natural gas in Finland, representing about 61% of the country's total gas consumption, while the industry and

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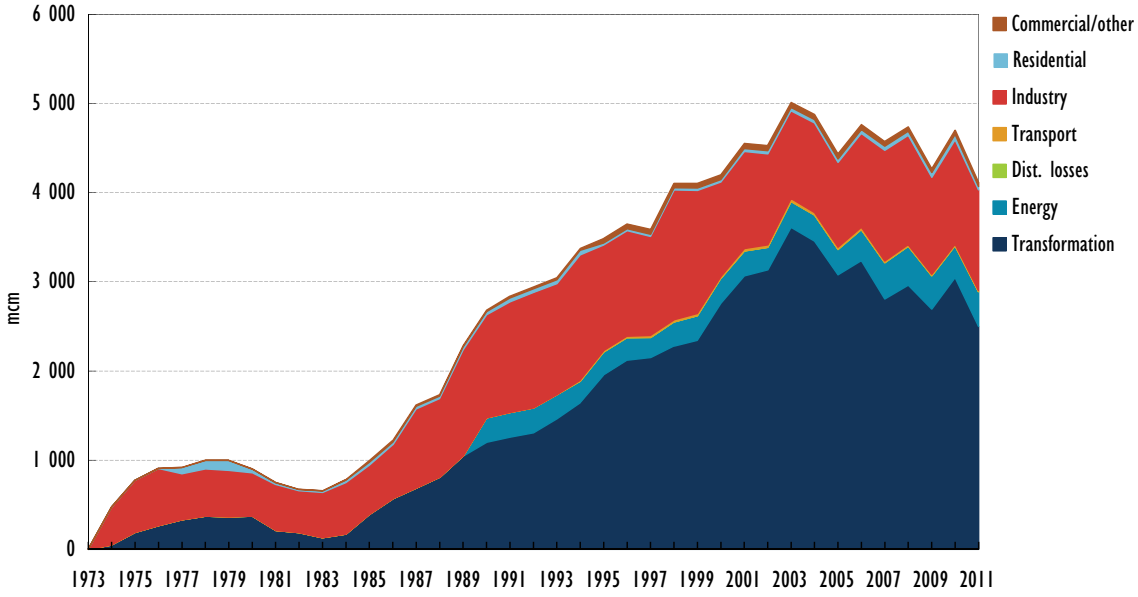
the energy sector represented 27% and 10%, respectively. Finnish daily peak gas demand stood at some 22.1 mcm/d on 18 February 2011, and the hourly peak consumption was 0.96 mcm/h on 8 January 2010.

Figure 4.8.6 Natural gas consumption by sector, 1973-2011



Gas import dependency

Because of the absence of natural gas production, Finnish gas demand is entirely supplied by imports, all of which have come through a twin pipeline connecting with Russia since 1974. The amount of natural gas imports from Russia equal domestic consumption.

A single importer in the country, Gasum Oy, has agreed a contract to import Russian gas to Finland until the end of 2026. The maximum annual importing volume of the contract is 5.5 bcm.

Gas company operations

Gasum Oy is responsible for imports, transmission and wholesale trading of natural gas in Finland. It is the sole importer and wholesale supplier. The company is owned by a consortium of Fortum (major electricity company: 31%), OAO Gazprom (25%), the Government of Finland (24%) and E.ON Ruhrgas International GmbH (20%).

A subsidiary of Gasum Oy runs a secondary market called Gas Exchange, where customers can make direct transactions with each other. This market is open to gas users procuring over five mcm per year and certain retail sellers. Around 5% to 10% of total gas consumption is traded on the Gas Exchange. Although there are no interruptible contracts in Finland, Gasum Oy has a product "Gasum Miinus" used to buy back fixed deliveries through the Gas Exchange to reduce load. The TSO, Gasum Oy, acts as a clearing house to monitor the market.

There are over 30 regional distribution companies for regional consumers and other small-scale users in the retail market for gas in Finland. Some distributors are partly owned by Gasum Oy. In 2010, there were around 37 000 customers of natural gas, around 92% of which are households using natural gas for cooking. However, the share of those consumers in total consumption is below 1%, while 25 power plants accounted

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for around 45% of the total consumption, followed by heavy industry (42%) and district heating plants (9%). The Porvoo refinery, owned by Neste Oil Oy, is one of the largest consumers of natural gas.

Gas supply infrastructure

Ports and pipelines

All natural gas is imported from Russia through a twin pipeline system that can be operated separately. The maximum annual import capacity of the pipeline of 82.1 GW (around 8.2 bcm/y, 22.5 mcm/d or 0.95 mcm/h at net caloric value) in the domestic network is determined by a domestic compression centre. However, the hourly peak utilisation reached around 0.96 mcm/h in January 2010, thereby exceeding the maximum technical capacity. The normal utilisation rate of the Finnish gas pipeline network is about 85%. Finland has experienced a gas supply disruption only once during the past 20 years – this lasted one day and resulted from a pipeline accident near St Petersburg in the summer of 2007. At the time Gasum Oy used linepack gas to maintain gas supplies to consumers.

The transmission system operated by Gasum Oy has approximately 1 314 km of pipeline within Finland. Including the distribution grid, the total length of the gas pipeline grid is around 3 100 km. The system has three gas compressor stations with a compressor capacity of 64 megawatts (MW). The natural gas receiving station in Imatra measures the amount of natural gas brought into the country. The other two compressor stations are located in Kouvola and Mäntsälä with the central control centre located in Kouvola. The gas pressure of the existing pipelines is 30-54 bars. There are around 200 interfaces which connect with transmission pipelines, 131 of which are pressure reduction stations in the network.

The gas grid is currently confined to the southern region of Finland, but Gasum Oy is planning to expand its natural gas transmission network to the western part of the country, mainly to the cities of Turku and Naantali. The length of the pipeline extension will be about 200 km. In 2011, a new gas transmission pipeline was completed between Lempäälä and Kangasala (34 km). Gasum Oy has also completed the construction of a new pipeline from Mäntsälä to Siuntio (89 km).

In addition, a biogas production plant in Kouvola was connected to the natural gas transmission network in October 2011. The plant's biogas production capacity is about 7 gigawatt hours (GWh), or 0.6 mcm per year.

There is no third-party access to the gas pipelines. It will be applied if the gas network is connected to Baltic countries and other European countries, or if more than 25% of gas is supplied by another importer.

The Balticconnector project to connect Inkoo in Finland with Paldiski in Estonia, with a total capacity of 2 bcm per year, is under discussion in the context of the Baltic Energy Market Interconnection Plan (BEMIP) which was initiated by the European Commission in 2008. It will allow Finland to access gas markets and storage facilities in the Baltic States.

Storage

Finland has no large-scale gas storage capacity in the country. All natural gas storage facilities in Finland are in the form of pipelines and spherical storages for daily balancing and peak shaving, which amounts to around 10 to 14 mcm. In addition, Gasum Oy operates an LNG storage facility with a capacity of 2 000 m^3 for LNG produced in

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Porvoo. As this plant is not equipped with any sending capacity to the gas network, the produced LNG would be delivered by trucks or fed into the network through mobile LNG vaporisers with a capacity of 75 MW (or 0.18 mcm/d). This is used only for peak shaving, fuel for cruise ferries and industry.

A potential future connection to the Baltic countries via the Balticconnector project may create possibilities for gas storage in Latvia, as Finland's geological structure makes domestic storage very expensive to build.

Emergency policy

Key elements in Finland's overall gas security policy are compulsory stocks in the form of alternative fuels for fuel switching, control of excess supply and cut back of contractual supplies.

The Act on Compulsory Stockholding of Imported Fuels (1994) sets the standard of gas supply security for suppliers. The gas importer (Gasum Oy) and gas plants are required to hold alternative fuel stocks corresponding to three months of natural gas imports. Municipal users who consume over 15 mcm of natural gas per year are also obliged to hold alternative stocks corresponding to three months of consumption. Substitute fuels are light or heavy fuel oil and propane gas. Industry users consuming gas as raw material have no obligation. In the event of a gas supply disruption, the release of compulsory alternative fuel stocks would be decided by NESA.

According to the Act on Security of Supply (1992), the NESA holds alternative fuels for gas disruption, and it decides the amount of its stocks in the light of the government's objective to have stocks of imported fuels corresponding to five months' consumption of all imported fuels. It covers stocks for industrial use on which there is no stockholding obligation. An emergency supply fee of EUR 0.084 per MWh is levied on natural gas users in order to maintain the public stocks of alternative fuels.

The NESO has a permanent natural gas section composed of members representing Gasum Oy (the TSO), natural gas users in the communities and industrial users of natural gas, the Finnish Gas Association, NESA and Neste Oil Oy.

Emergency response measures

The Finnish TSO has an early warning system linked with a Russian control centre which is located 150 km from Finland. Through another data connection system with Russia, Gasum Oy is able to monitor pipeline flow to 500 km within Russia. This system allows Gasum Oy to monitor real time gas flows in Russia and receive early warning of potential disruptions in order to implement contingency plans by switching to the parallel gas pipeline or by deploying emergency response measures.

When a shortage of gas supply is anticipated, the TSO will first endeavour to curb consumption by increasing the price of excess gas and implementing a buy-back system through the Gas Exchange. If these measures are insufficient to mitigate the impact of a gas disruption, the TSO will reduce the contractual capacities of all its customers on a *pro rata* basis, except for protected customers (detached houses and other residential properties that directly use natural gas), as most residential buildings cannot use substitute fuels. Consumers can also reduce their own consumption more than required by the TSO, and they can sell their quota to other customers through secondary market trade.

In the event that the natural gas supply is totally interrupted, NESA can give permission to release compulsory stocks of alternative fuels, according to the Act on Compulsory

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Stockholding of Imported Fuels. Public stocks of alternative fuel stocks for natural gas held by NESA would be released by a decision of the government according to the Act on the Security of Supply. Over 40% of natural gas consumption can be switched to light fuel oil within 8 hours of fuel switching.

An air-propane mixing plant has been built in Porvoo to provide protected customers with air-mixed propane gas. The plant can be activated only when the pressure in the transfer pipelines falls below 7 bars. The gas mixture capacity of the plant is equivalent to 350 MW (or 0.84 mcm/d), by which the gas demand of protected customers (200 MW or 0.48 mcm/d) can be covered.

The total emergency stock of LPG is 36 500 tonnes (46.7 mcm of natural gas), around 70% of which is owned by NESA. In addition to protected customers, LPG stocks are also envisioned for use in the Porvoo refinery in case of a natural gas disruption, as it is one of the largest consumers of natural gas.

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France

Key data

Table 4.9.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	71.4	43.6	35.9	30.5	30.5	26.9	19.9
Demand (kb/d)	1 826.1	2 000.6	1 990.9	1 833.4	1 792.4	1 739.8	1 588.4
Motor gasoline	393.2	318.4	250.7	184.9	175.1	160.2	-
Gas/diesel oil	737.0	924.7	1 000.1	983.4	962.1	963.9	-
Residual fuel oil	174.1	136.8	118.1	92.0	81.9	71.8	-
Others	521.7	620.7	622.0	573.1	573.2	544.0	-
Net imports (kb/d)	1 754.7	1 957.0	1 955.0	1 802.9	1 761.9	1 712.9	1 568.5
Import dependency (%)	96.1	97.8	98.2	98.3	98.3	98.5	98.7
Refining capacity (kb/d)	1 820.0	1 901.9	1 951.3	1 997.5	1 997.5	1 997.5	-
Oil in TPES (%)**	37	32	31	29	30	29	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.9.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	2 857	1 878	1 149	777	609	541	377
Demand (mcm/y)	28 232	39 753	47 170	49 127	42 764	44 147	44 915
Transformation	500	3 333	6 307	8 684	9 085	0	-
Industry	12 699	16 292	13 297	12 035	11 500	0	-
Residential	7 540	19 079	16 685	16 013	13 019	0	-
Others	7 493	1 049	10 881	12 395	9 160	0	-
Net imports (mcm/y)	25 375	37 875	46 021	48 350	42 155	43 606	44 538
Import dependency (%)	89.9	95.3	97.6	98.4	98.6	98.8	99
Natural gas in TPES (%)	11	14	15	16	15	15	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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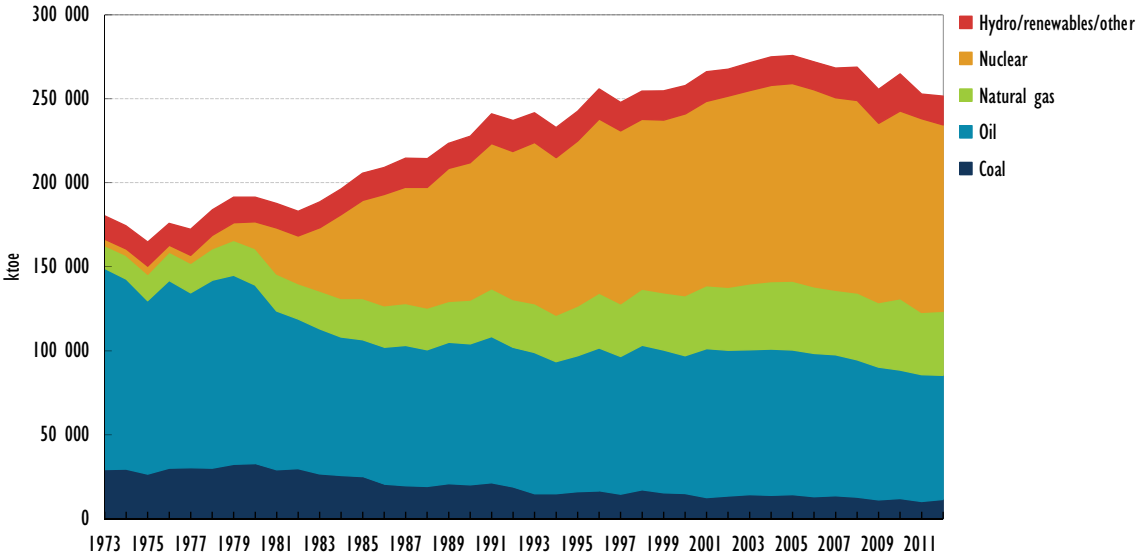
Figure 4.9.1 Total primary energy source (TPES) trend, 1973-2012



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Map 4.9.1 Oil infrastructure of France

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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Map 4.9.2 Gas infrastructure of France

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Country overview

Oil has been one of the dominant – although declining – energy sources in France, accounting for 29% of the country's total primary energy supply (TPES) in 2012.

France has very little domestic oil production, averaging 27 thousand barrels per day (kb/d) in 2012, while France's oil demand stood at 1.7 million barrels (mb) in the same year. The transport sector consumed 57% of total oil supply in 2011, with diesel alone accounting for 39% of oil product demand. France's oil imports were 2 mb/d in 2012. France has relatively well diversified crude import sources, with a range of OPEC countries accounting for around 43% of imports, and countries from the former Soviet Union (FSU) accounting for a further 32%.

The use of emergency oil stocks is central to France's emergency response policy, which can be complemented by demand restraint measures. The Minister for Ecology, Sustainable Development and Energy is responsible for energy security of supply issues in France.

All industry operators in France are required to hold the equivalent of 29.5% of the volume of oil they released for domestic consumption during the previous calendar year. These compulsory industry stocks fully cover France's International Energy Agency (IEA) 90-day obligation. In meeting the stockholding requirement, industry operators are obliged to hold a portion of the stocks through a central stockholding agency, the Comité Professionnel des Stocks Stratégiques Pétroliers/ Société Anonyme de Gestion des Stocks de Sécurité (CPSSP/SAGESS). SAGESS is a privately owned and managed entity with the sole function of holding and maintaining emergency reserves under the direction of the CPSSP.

At the end of April 2013, France held some 163 million barrels (mb) of oil stocks (108 mb of agency stocks and 51 mb of industry stocks), equating to 100 days of 2012 net imports. Around 48% of total stocks were held in the form of middle distillates, followed by crude oil (30%).

The share of natural gas in the country's TPES has steadily increased from 11% in 1990 to 15% in 2012. France produced some 0.5 billion cubic metres (bcm) of natural gas in 2012, which covered only 1% of total domestic consumption. Gas demand was 44 bcm, or 121 million cubic metres (mcm/d) in 2012, down from 49 bcm in 2010. In 2011, the residential sector represented about 31% of total gas consumption, while the industry and transformation sectors represented 27% and 21% respectively.

France's natural gas imports in 2012 amounted to some 45 bcm. French natural gas imports are relatively well diversified with significant imports from Norway (42% of the total import), the Netherlands (17%), the Russian Federation (16%) and Algeria (8%).

The maximum gas supply capacity of France's natural gas infrastructure – pipeline imports and liquefied natural gas (LNG) regasification and peak storage output – is 528 mcm/d, while peak daily natural gas demand was some 340 mcm/d (3 675 GWh) on 8 February 2012. This leaves over 180 mcm/d (or 35%) "spare" capacity in the natural gas network.

French natural gas security of supply relies primarily on diversification of import sources, infrastructure and supply routes, and extensive gas storage facilities.

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Oil

Market features and key issues

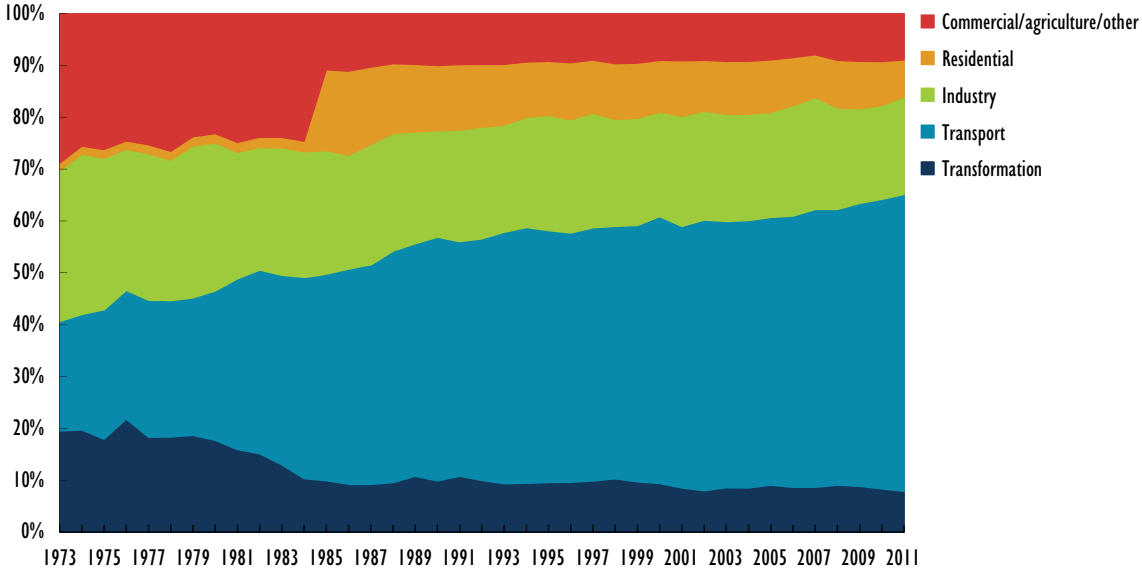
Domestic oil production

France's domestic oil production is very modest. Production averaged 27 kb/d in 2012 – equivalent to only 1.5% of total demand.

Oil demand

In 2012, France's oil demand was 1.7 mb/d, down from around 1.8 mb/d in 2010. French oil demand has had a downward trend since 1999. In 2011, transport consumed 57% of total oil supply, with diesel alone accounting for 39% of oil product demand (up from 24% in 1996). Industry was a distant second at 19% of total oil product demand in 2011. Its share has been relatively constant over the past decade.

Figure 4.9.2 Oil consumption by sector, 1973-2011



The decreasing trend of oil consumption is expected to continue. The IEA forecasts a 9% decrease in demand for the period 2012-18.

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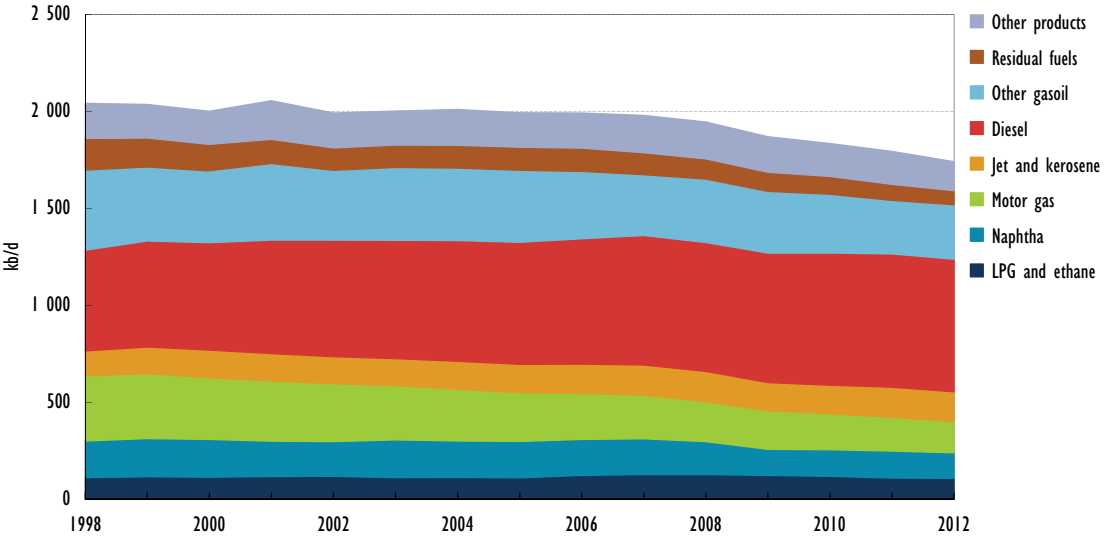
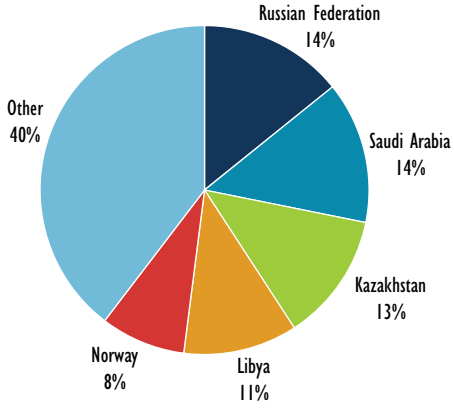
Figure 4.9.3 Oil demand by product, 1998-2012



Imports/exports and import dependency

France's oil imports were 2 mb/d in 2012, consisting of 1.1 mb/d of crude oil and 0.9 mb/d of oil products. France has relatively well diversified crude import sources, with a range of OPEC countries (notably Saudi Arabia and Libya) accounting for around 43% of imports, and countries from the FSU accounting for a further 32%, notably Russia (14%) and Kazakhstan (13%). With regard to products, nearly 62% of refined product imports came from OECD countries (73% of this from Europe), with another 20% from the FSU.

Figure 4.9.4 Crude oil imports by origin, 2012



Oil company operations

Total is the main oil company in France. A French multinational company, it is one of the six largest international oil and gas companies in the world. Total operates in all aspects of both the upstream and downstream sectors including oil and gas exploration, refining, petroleum product retailing, international crude oil and product trading and chemicals manufacturing.

The French motor fuel market is very competitive. The total number of filling stations has declined over the past three decades, with numbers dropping from 40 400 in 1980

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to 15 600 in 2000, and a further decline to 12 158 in 2010. The trend towards the closure of filling stations is likely to continue but the rate of decline is decreasing.

Oil supply infrastructure

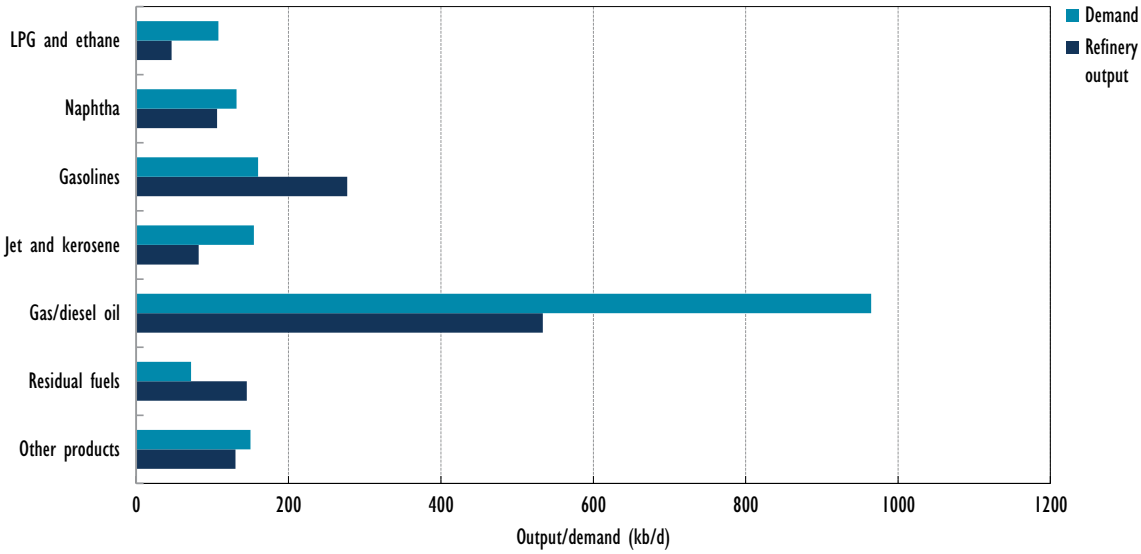
Refining

France currently has eight operating refineries with a combined capacity of 1.4 mb/d. Because of recent significant reductions in French refining capacity, overall capacity in 2012 was down sharply from previous years where it had been relatively stable at around 2 mb/d. Total closed its 140 kb/d Dunkerque refinery in the North of France in 2010 and Petroplus shuttered the 80 kb/d Reichstett plant in 2011. Furthermore, both Petroplus' Petit-Couronne refinery (150 kb/d) and LyondellBasel's Berre refinery (126 kb/d) were also shut down in 2013 and 2012, respectively.

The largest refinery operator in continental France is Total. The company operates five refineries with a combined refining capacity of 790 kb/d in 2012. The next largest operator is Esso with two refineries and a combined refining capacity in 2012 of around 360 kb/d. The other refinery operator is Petroineos (a joint venture of Ineos and Petrochina) with one refinery and a refining capacity of some 200 kb/d in 2012.

In 2012, the country's refined product output totalled 1.2 mb/d (a refining capacity utilisation rate of almost 86%). The composition of production was gas/diesel oil (40%), motor gasoline (21%), residual fuel oil (11%) and naphtha (8%).

Figure 4.9.5 Refinery output vs. demand, 2012



France had a gas/diesel oil deficit of around 430 kb/d in 2012, which indicates that France has a gas/diesel import dependency of 45%. France also encountered a jet/kerosene deficit of some 70 kb/d in 2012. The import dependency of liquefied petroleum gas (LPG) also stood at over 50%.

Ports and pipelines

Since the closure of Total's Dunkerque refinery, crude oil is imported into France through three main sea ports at Marseille, Le Havre, Saint-Nazaire in Metropolitan France and Fort-

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de-France in Martinique. In 2012, approximately 64 million tonnes (Mt) of crude oil was unloaded at these ports, 50% at the port of Marseille and 40% at Le Havre. After unloading, the oil is processed in refineries near these ports or by inland refineries connected to the ports by pipelines; however some oil transits France via pipeline to Switzerland.

There are two major crude oil pipelines in France. The first of these is the South European Pipeline System (SPSE) from Fos (Marseille) to Cressier (Switzerland) via Lyon. The SPSE has a maximum authorised flow of 70 Mt/y (or 1.4 mb/d). It had supplied refineries in France (Feyzin), Switzerland (Cressier) and Germany (Miro), but the Miro refinery decided to stop using the SPSE pipeline as it started to import crude oil through the Trans-Alpine (TAL) pipeline from Italy to Germany. The economic efficiency of the SPSE has been weakened by the closure of refineries (such as the Reichstett refinery in 2010 and the temporary closure of Cressier refinery in early 2012) and competition from the TAL pipeline.

The other major crude oil pipeline in France is the Le Havre to Grandpuits (PLIF) pipeline, with a maximum authorised flow of 11.5 Mt/y (or 230 kb/d) and a utilisation rate of 34%.

There are four major product pipelines in France with a total capacity of 77 Mt/y (or around 1.5 mb/d).

Storage capacity

French oil storage capacity has been in decline in recent years. Approximately 100 oil depots have closed since 2001 owing to factors such as urbanisation, cost-cutting necessitated by increasing competition and the regulation of industrial risks.

The French stockholding agency, SAGESS, holds stocks in 100 storage facilities around the country, which stores over 100 mb of emergency crude oil and product stocks.

Decision-making structure

The Minister for Ecology, Sustainable Development and Energy is responsible for energy security of supply in France. Under this minister and the Minister for the Environment, the General Directorate for Energy and Climate Change (DGEC) is responsible for formulating and implementing energy and climate change policy.

Within the DGEC, the Directorate for Energy (DGEC/DE) is responsible for the oil and gas sector with regard to security of supply, monitoring and supervision of strategic stocks and managing supply emergencies. It is responsible for the preparation and maintenance of oil emergency response plans, and during an oil supply emergency it acts as the national emergency strategy organisation (NESO).

The French NESO can draw on a large number of staff when necessary from the CPSSP/SAGESS stockholding agency and from the DGEC/DE Sub-Directorate of Security of Supply and New Energetics, whose primary role is to guarantee the security of French oil and gas supply.

In order to effectively carry out its role, the DGEC/DE maintains a network of relationships with other government departments and professional organisations. Approximately 100 professionals from industry and the distribution sector are appointed on a voluntary basis to act as participants during a national crisis.

As soon as an emergency develops, the DGEC/DE can adapt its organisation to the specific nature of the emergency. In the case of a major emergency, the DGEC/DE activates an emergency cell which monitors market conditions and is in permanent contact with the prefects (local representatives of the government either in the *zone de défense* or in the *département*).

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Stocks

Stockholding structure

All industry operators are required to hold the equivalent of 29.5% of the volume of oil released for domestic consumption during the previous calendar year. These compulsory industry stocks fully cover France's IEA 90-day obligation.

In meeting the stockholding requirement, industry operators are obliged to hold a portion of the stocks through the central stockholding agency, the CPSSP/SAGESS. They may choose to delegate either 56% or 90% of their stockholding obligation to the agency. Therefore, these companies are obliged to be directly responsible for either 44% or 10% of their strategic reserve obligation. Typically, industry participants such as hypermarkets (which have an obligation because of their sale of vehicle fuels) choose to delegate the maximum amount possible to the agency, and may meet their remaining obligation through the use of tickets. Operators such as refiners usually choose the option of holding 44% of their obligation.

SAGESS is a privately owned and managed entity with the sole function of holding and maintaining emergency reserves under the direction of the CPSSP. Although a small part of the stockholding obligation delegated to CPSSP is covered through ticketing, SAGESS manages most of the collectively held reserves in France.

Crude or products

At the end of April 2013, France held some 163 mb of oil stocks (108 mb of CPSSP/SAGESS stocks and 51 mb of industry stocks), the equivalent of 100 days of 2012 net imports. Around 48% of total stocks were held in the form of middle distillates, followed by crude oil (30%).

The stockholding requirement covers four product categories: motor gasoline, gas/diesel oil, kerosene/jet fuel and fuel oil. SAGESS has minimum motor gasoline and diesel oil stock requirements for each geographic zone. Companies are allowed to substitute a share of the product obligation with crude oil, in line with European Union legislation. There is no specific ethanol storage for the 90-day obligation.

Location and availability

Emergency stocks owned by SAGESS at the end of April 2013 stood at about 108 mb, accounting for about two-thirds of the country's total stocks. The stocks are stored in 120 rented storage capacities throughout France. The stocks are mainly commingled with commercial stocks.

Bilateral stockholding has a marginal role in the French system. SAGESS holds 2.2 mb of diesel in Belgium, 1.3 mb of jet fuel in Germany and 130 kb of fuel oil in the Netherlands.

Monitoring and non-compliance

The DGEC is responsible for organising audits. It also has the authority to require operators to provide any information deemed necessary during an oil supply emergency. If an operator foresees their stocks falling below minimum requirements they have three options: stop selling; borrow stock from another company; or purchase additional stock on the spot market.

There is a strong disincentive for companies not to meet their emergency stockholding obligations, as failure to do so carries very strong penalties – up to 54 times the avoided

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cost of compliance. A penalty of up to EUR 1 500 per day can also be imposed if a lack of reporting is established.

Stock drawdown and timeframe

The process for drawing down stocks is initiated with a political decision of the ministry in charge of energy (which is normally based on an assessment provided by the DGEC/DE). Then, orders or rulings are established – usually within 48 hours. Different types of measures may be selected: agency stocks location exchange (relocalisation), agency stocks loan, authorisation for industry stock release, general lowering of compulsory stockholding obligation, releasing of CPSSP tickets or sale of agency stocks.

The loan or exchange of agency stocks is allocated according to the market shares of the operators. An industry stock release is managed by the operators themselves, and the speed at which the drawdown can take place depends primarily on their drawdown capacities. A stock release via CPSSP tickets requires the agreement of affected operators and may only occur as a last resort because of competition considerations. Bilateral agency stocks may be mobilised in the same way as other stocks. SAGESS does not usually sell stocks: it loans them out instead. The deadline for reimbursing non-emergency SAGESS stock loans is one month, during which time SAGESS retains full ownership. SAGESS agrees to two to three requests per month for such loans. There is a fee for the loan process but no charge (interest, etc.) for SAGESS loans.

Financing and fees

No financial assistance or public funding is provided to industry in order to maintain emergency reserve requirements.

The CPSSP oversees stockholding strategy and is managed by a board composed of refiners, other oil industry operators (notably supermarkets) and representatives from the government, including DGEC/DE, with the right of veto. Each year the agency calculates the obligation of the individual operators, incorporating the previous year's consumption, and the fees necessary for building and maintaining the designated stock levels. The new obligation level becomes effective as of 1 July. Industry participants must pay the CPSSP the calculated fee to cover the storage costs of the oil delegated to the agency.

Other measures

Demand restraint

France has a wide range of oil demand restraint measures to complement emergency stock release – ranging from voluntary to compulsory, and short term to long term. These measures – 89 in total – are set out in the Hydrocarbon Resources Plan (PRH).

In the PRH document, the 89 measures are each summarised in a brief sentence, classified into one of eight different categories and assigned a numbered code. The categories cover various fields, including personal transport, goods transport, private premises and dwelling, public premises, industry and oil deliveries limitation.

Each measure is characterised by the description of the principal actors involved and the oil products to which the measure applies. The description of the measures also includes criteria for their execution, geographical scope, the locus or responsibility for implementation of the measure, duration, legal basis and its mandatory nature. Each crisis is assessed on a case-by-case basis and dealt with at the appropriate level: ministry (DGEC/DE), defence zone (defence zone prefects) and *département* (prefects).

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All decisions at the local level are made through the local prefect who in turn reports to the Minister of Internal Affairs.

Fuel switching

The capacity for fuel switching in France is considered to be negligible. There are no government regulations in this area and the share of oil in power generation was only 0.6% in 2012.

Other

The capacity for short-term surge production in France is negligible and there are no government regulations in this area. Domestic oil production is only equivalent to 1.5% of total consumption.

Gas

Market features and key issues

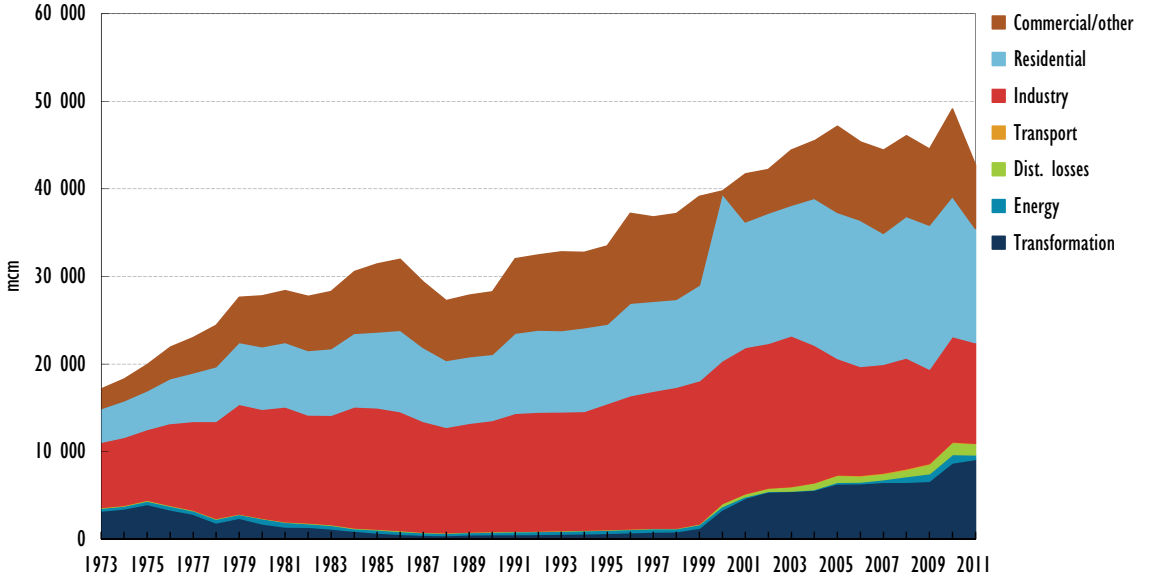
Gas production and reserves

France produced some 0.5 bcm of natural gas in 2012, which covered only 1% of total consumption. Because of its very small indigenous gas production, almost all gas demand in France is met by imports.

Gas demand

With corrections for climatic variations, natural gas demand was 44 bcm (or 121 mcm/d) in 2012, down from 49 bcm in 2010. In 2011, the residential sector represented about 31% of total gas consumption, while the industry and transformation sectors represented 27% and 21% respectively.

Figure 4.9.6 Natural gas consumption by sector, 1973-2011



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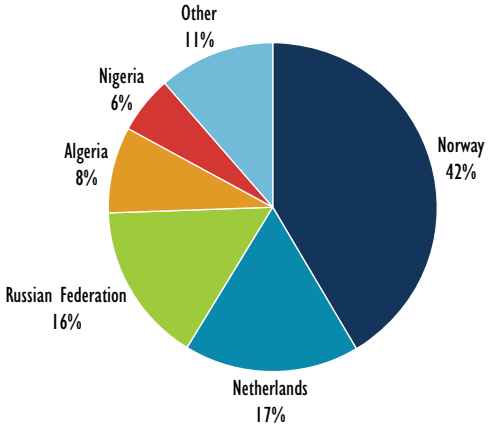
Monthly peak gas demand was recorded in December 2010, standing at 7.5 bcm per month, while daily peak demand stood at some 340 mcm/d (3 675 GWh) on 8 February 2012.

Gas import dependency

France's natural gas imports in 2012 amounted to some 45 bcm. French natural gas imports are relatively well diversified with significant imports from Norway (42% of total imports), the Netherlands (17%), Russia (16%) and Algeria (8%). Entry capacities to the French gas network were around 265 mcm/d at the end of 2012 – with 72% of this for gas pipelines and 28% for LNG terminals.

Figure 4.9.7 Natural gas imports by source, 2012



Gas company operations

The French gas market has been fully open to competition since 1 July 2007 when the government unbundled the gas transmission network operator GRTgaz. There are two gas transmission system operators (TSOs) in France.

GRTgaz (75% subsidiary of GDF Suez, 25% owned by a public consortium) is the largest TSO in France. It operates around 87% of the gas transmission grid in France. GDF Suez is vertically integrated and a dominant player in the French gas market, and has the largest gas transport network in Europe.

The second TSO is Total Infrastructures Gaz France (TIGF), which was owned as a subsidiary of Total but became a consortium of Snom, EDF and GIC in 2013. It operates the gas grid and gas storage facilities in southwest France. TIGF operates about 13% of the French gas network.

Gas supply infrastructure

Ports and pipelines

The maximum gas supply capacity of France's natural gas infrastructure (pipeline imports, LNG regasification and peak storage output) is 528 mcm/d, while peak daily natural gas demand was some 340 mcm/d. This leaves over 180 mcm/d (or 35%) "spare" capacity in the natural gas network.

France has numerous cross-border gas pipelines, with a total import capacity of 187.5 mcm/d. Also, there are three LNG port terminals in France: Fos Cavaou and Fos

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Tonkin near Marseilles, and Montoir-de-Bretagne on the Atlantic coast. These terminals are owned by Elengy (except Fos Cavaou which is 70% owned by Elengy and 30% owned by Total). Their combined regasification capacity in 2010 was 72.5 mcm/d.

EDF confirmed its investment in developing a fourth LNG terminal at Dunkerque in the northwest which is expected to enter into service by the end of 2015 with a regasification capacity of 33.5 mcm/d. There are also plans to expand the capacity of the existing terminals at Fos Tonkin (1.5 bcm/y) and Montoir (2.5-6.5 bcm/y) from 2015.

The gas transmission system consists of approximately 37 500 km of pipelines operated by two TSOs. GRTgaz is the largest, with a 32 500 km network of pipelines covering 87% of the country. The other TSO, TIGF, has a 5 000 km pipeline network in the southwest of the country. The networks of the two operators are interconnected in Castillon-la-Bataille (Dordogne) and Cruzy (Hérault).

The French transmission grid has three balancing zones: Northern GRTgaz, Southern GRTgaz, and South-Western TIGF.

One sector of the network in the north of France uses L-gas – a low-calorific gas from the Netherlands which cannot be used interchangeably with the H-gas (high calorific) in the rest of the network. The main potential threats to the L-gas network would be a long-term technical failure of the interconnection with Belgium (or retention of L-gas in Belgium because of a domestic supply shortfall), or a disruption in L-gas supply from the Netherlands. A limited amount of L-gas is stored in the north of France – 12 terawatt hours (TWh) in Gournay – and there are conversion units at Dunkerque that can convert H-gas into L-gas if the need arises. Also, four other European countries use L-gas and the Netherlands' production capacity is flexible.

In addition to the gas transmission network, France has a 193 700 km gas distribution network that is owned by local communities and managed by 26 operators.

Storage

The country's total gas storage capacity is approximately 13 bcm. It consists of 12 bcm in aquifers, 1 bcm in salt caverns and 0.1 bcm in a depleted reservoir.

There are two main underground gas storage operators in France. Storengy, a 100% subsidiary of GDF Suez, operates 13 storage sites in France. These include: nine aquifers (centred on the Paris Basin), three salt caverns (in southeast France) and one depleted reservoir. Storengy's total storage capacity is 10.4 bcm (around 80% of French storage capacity), with a maximum withdrawal rate of 230 mcm/d. The other underground gas storage operator, TIGF, operates two storage sites in France. These are both aquifers located in southwest France at Izaute and Lussagnet. The total volume stored at the two TIGF sites is 2.7 bcm.

There is also some storage capacity available in Belgium and Germany, with direct interconnections to the French network that can be used to supply the French market – but the quantities available are limited.

Emergency policy

France's security of natural gas supply relies primarily on the diversification of import sources, infrastructure and supply routes, as well as extensive gas storage facilities.

According to the government, the French natural gas network meets the N-1 standard of the European regulation (Regulation 994/2010) at a level of 130%. This means that it has the resilience to satisfy total gas demand even in the event of an outage of the single largest gas infrastructure, during a day of exceptionally high gas demand.

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The main domestic regulatory tool in case of an interruption to the natural gas supply is the Order of 27 October 2006 on National Emergency Measures together with a National Contingency Plan aimed at the prevention and management of a natural gas supply crisis. The plan includes emergency measures, the legal framework in which they are embedded and fixed principles regarding their implementation.

Activation of the National Contingency Plan requires a decision by the minister responsible for energy and is implemented in the case of: disruption or interruption of gas supply, inability to ensure balance between supply and demand on the French market, dysfunction of gas networks and gas facilities located on the national territory, other crises affecting the operation of the gas system or France's participation in the implementation of emergency measures decided in collaboration with one or more EU member states or the European Union.

Another important development with regard to natural gas emergency policy in France has been the ongoing implementation of EU Regulation 994/2010 on measures to safeguard security of gas supply. Implementation requires the completion of a natural gas security risk assessment and the development of emergency and preventive action plans – in collaboration with neighbouring EU member states when necessary.

In a gas supply crisis the key focus of industry participants is meeting their legal commitments to maintain consumer supply. This was the case during the 2009-10 crisis when an interruption to the flow of Russian gas via Ukraine occurred in conjunction with an acute cold snap and domestic industrial action. During this time the gas companies had daily contact with the government through a designated emergency contact and maintained their normal focus on meeting their commitments to their customers.

Emergency response measures

Decree No. 2006-1034, dated 21 August 2006, sets out the principles for natural gas storage access and use. The decree also confers rights for storage capacity to providers who directly supply end consumers. An amended order in February 2007 determined the amount of storage rights associated with each customer on the basis of their characteristics of consumption.

There is little scope for demand restraint to address a gas supply emergency in France, as the country's natural gas security mainly focuses on diversification of import sources and extensive gas storage facilities.

In 2013 the government initiated a consultation aimed at strengthening the regulation to keep storage of natural gas on an appropriate level. This is because narrowing gas price spread between summer and winter has discouraged French suppliers from injecting natural gas into storage facilities during the summer.

France has no specific policies to promote fuel switching. The potential for short-term fuel switching is not known precisely, except in the power generation sector where only one EDF plant at Montereau (with daily consumption of 1.39 mcm/d) has the flexibility to switch from gas to fuel oil. The share of natural gas in electricity generation amounts to less than 4%.

The number of interruptible contracts has declined significantly in past years and represents less than 5% of total winter demand.

The capacity for short-term surge production is negligible in France and there are no government regulations in this area. Domestic natural gas production is only equivalent to some 1% of total consumption.

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Germany

Key data

Table 4.10.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	102.7	85.8	113.2	76.1	79.9	79.1	59.7
Demand (kb/d)	2 681.8	2 766.8	2 620.7	2 469.6	2 396.6	2 388.3	2 238.7
Motor gasoline	724.0	665.1	542.4	454.3	453.5	426.8	-
Gas/diesel oil	1 107.8	1 163.1	1 110.0	1 096.2	1 050.4	1 076.2	-
Residual fuel oil	212.9	168.1	175.8	147.5	142.8	134.2	-
Others	637.0	770.5	792.4	771.6	749.8	751.2	-
Net imports (kb/d)	2 579.1	2 681.0	2 507.5	2 393.5	2 316.7	2 309.2	2 179.0
Import dependency (%)	96.2	96.9	95.7	96.9	96.7	96.7	97
Refining capacity (kb/d)	1 507.0	2 275.3	2 323.2	2 465.7	2 465.7	2 465.7	-
Oil in TPES (%)**	35	37	34	32	33	33	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.10.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	18 919	22 049	19 850	13 042	14 828	12 298	8 760
Demand (mcm/y)	69 723	87 728	98 193	90 040	81 546	87 201	82 374
Transformation	15 872	15 679	22 550	24 006	22 425	0	-
Industry	25 123	27 227	24 433	26 174	26 004	0	-
Residential	17 455	29 802	36 558	27 893	20 770	0	-
Others	11 273	15 020	14 652	11 967	12 347	0	-
Net imports (mcm/y)	50 804	65 679	78 343	76 998	66 718	74 903	73 614
Import dependency (%)	72.9	74.9	79.8	85.5	81.8	85.9	89
Natural gas in TPES (%)	16	21	24	22	22	22	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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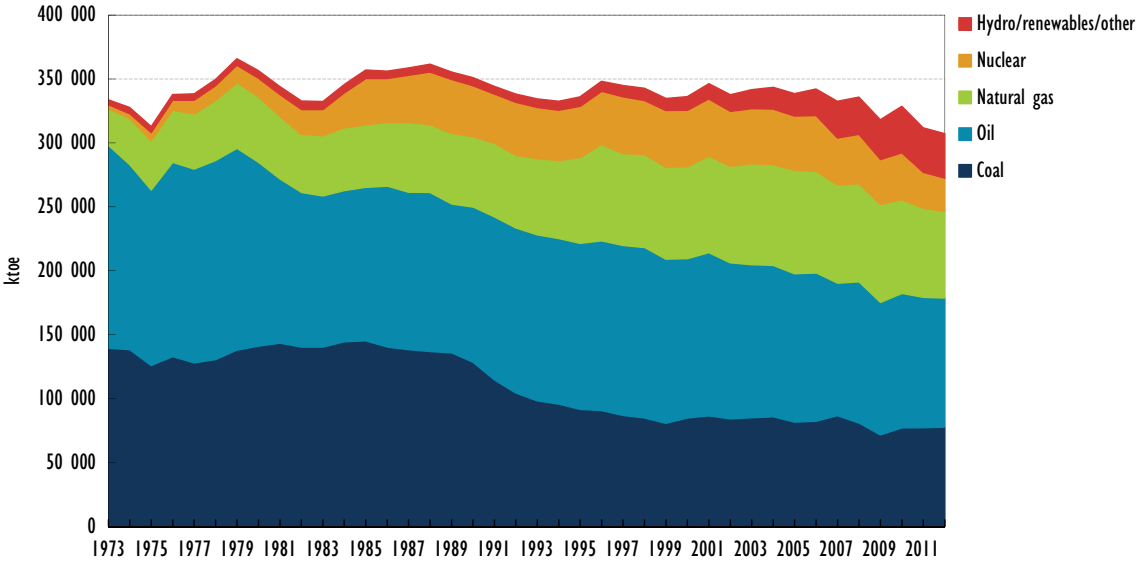
Figure 4.10.1 Total primary energy source (TPES) trend, 1973-2012



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Map 4.10.1 Oil infrastructure of Germany

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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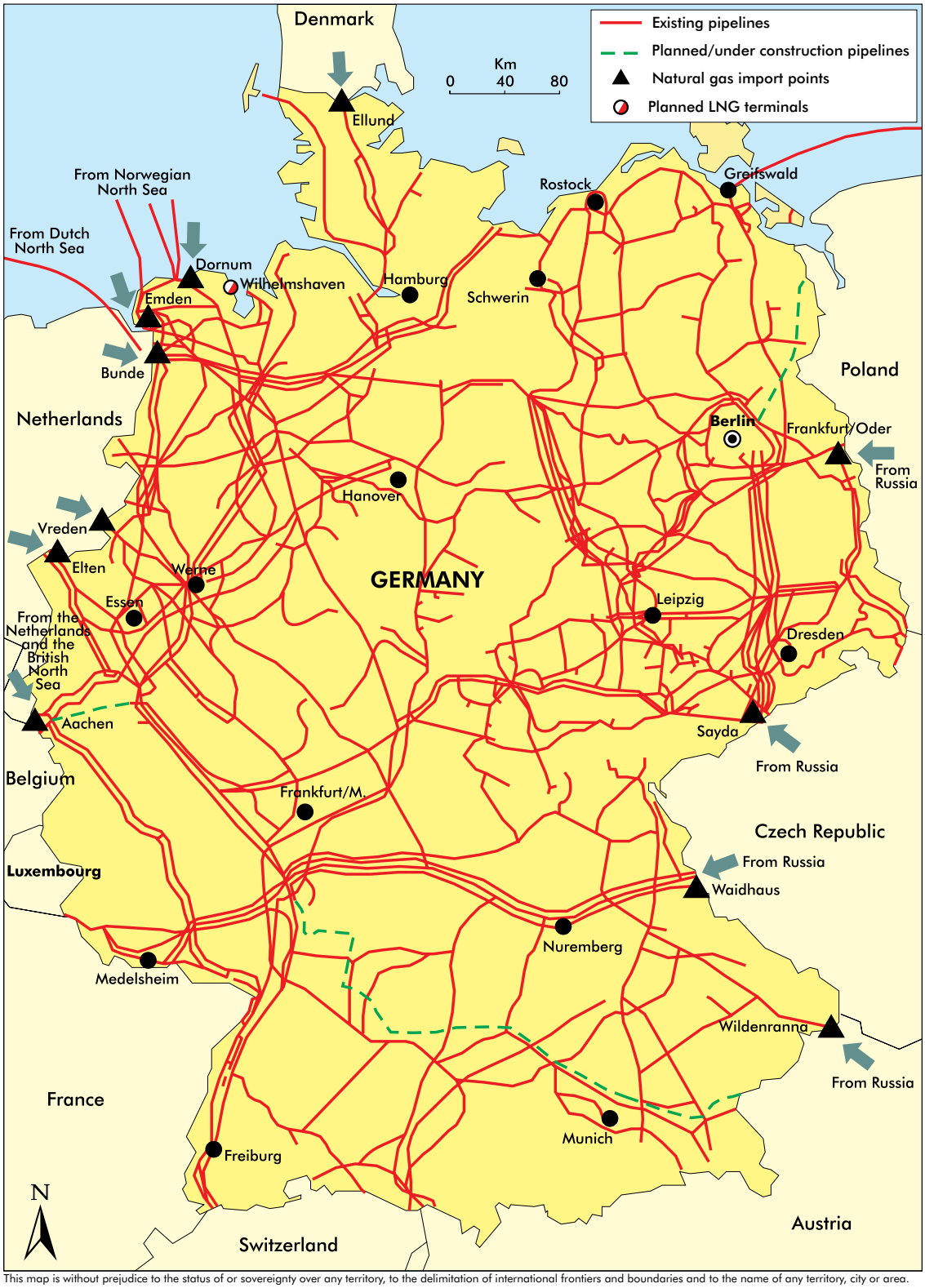
Map 4.10.2 Gas infrastructure of Germany



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Country overview

Germany has very little domestic oil and natural gas production and relies heavily on imports. It has a diversified and flexible oil and natural gas supply infrastructure, which consists of crude, oil product and natural gas pipelines and crude and oil product import terminals. Natural gas is imported into Germany exclusively by cross-border pipeline. The country has no liquefied natural gas (LNG) infrastructure, although some German companies have booked capacities in overseas LNG terminals.

Oil continues to be the main source of energy in Germany although its share of the energy mix has declined markedly since the early 1970s. It now represents approximately 33% of Germany's total primary energy supply (TPES).

Natural gas demand in Germany has declined more than 11% since 2005. Demand was 87.2 billion cubic metres (bcm) in 2012, down from 90 bcm in 2010 and 98.2 bcm in 2005. According to government-commissioned analysis, the total consumption of natural gas in Germany is expected to continue to decline over the long term. The share of natural gas in Germany's TPES is currently around 22%.

Since 1998, the German oil stockholding agency (EBV) has been solely responsible for meeting Germany's 90-day stockholding obligation. Germany's Oil Stockholding Law (1978, amended in 1987 and 1998) stipulates that the EBV shall constantly maintain stocks of oil and petroleum products at a level equivalent to or above 90 days of net imports. There is no minimum stockholding obligation on industry, so industry-held commercial stocks are held in addition to the EBV stocks.

There are several legal tools available to German authorities for natural gas emergency response. These include ordinances that can be used to restrict the sale, purchase or use of goods, both in terms of quantity and time, or permit them only for certain priority purposes, to ensure that vital energy needs are met.

There are no compulsory natural gas storage requirements in Germany, and no state-owned storage facilities. Operators of gas storage facilities must grant other companies access to their storage facilities and auxiliary services at a fair market price. There are 50 gas storage facilities in Germany, with a total capacity of 22.7 bcm. German firms also have access to natural gas storage in Haidach, Austria which has a capacity of 2.6 bcm.

Oil

Market features and key issues

Domestic oil production

Oil remains the most significant (although declining) energy source in Germany, accounting for 33% of TPES in 2012, up slightly from 32% in 2010. However, Germany has very little domestic crude oil production – equivalent to just over 2% of oil demand – and the government expects that production will slowly decline in the foreseeable future. According to figures of the International Energy Agency (IEA), German crude oil production (excluding non-conventional oils) averaged 56 thousand barrels per day (kb/d) in 2012, up from 55 kb/d in 2011 and 49 kb/d in 2010.

Oil demand

In 2012, Germany's oil demand was 2.4 mb/d, down from 2.5 mb/d in 2010 – continuing a downward trend since 1998. The road transport sector is the largest consumer of oil

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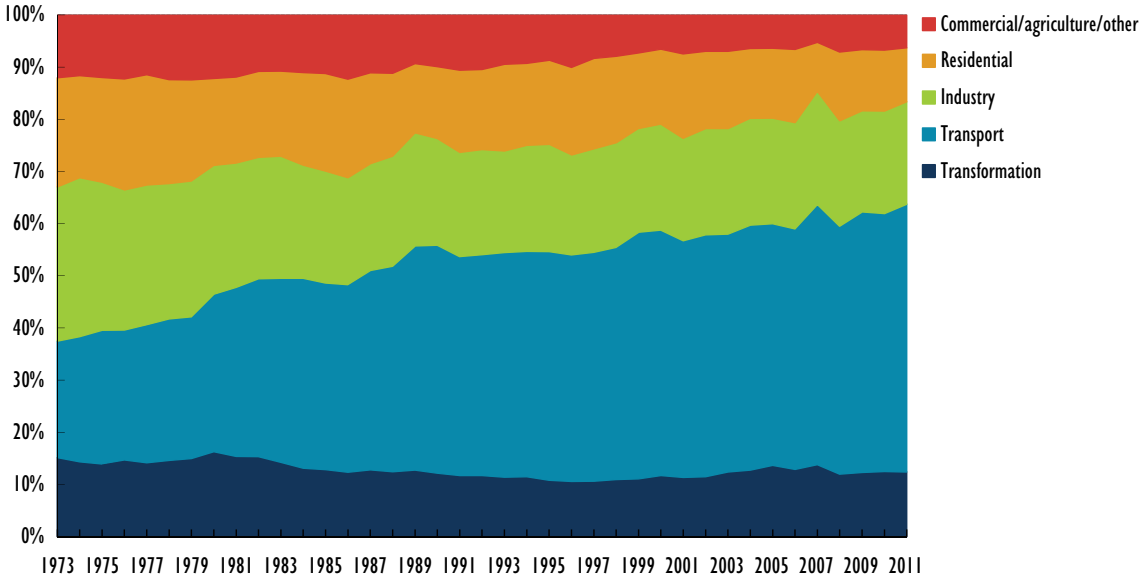
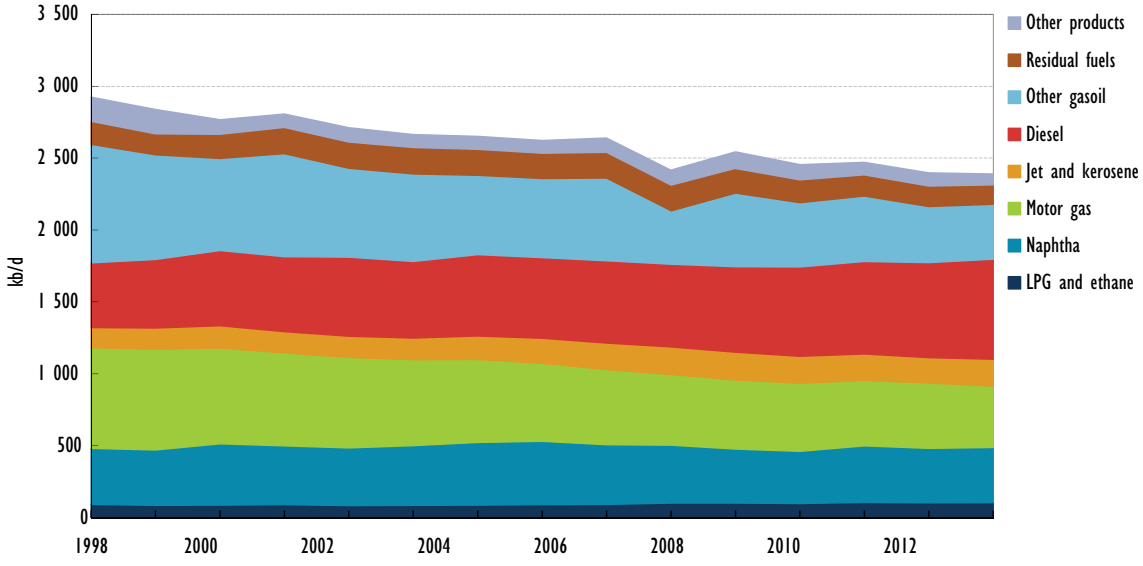
in Germany, consuming 51% of total oil supply in 2011, with diesel alone accounting for 29% of oil product demand in 2012 (up from 15% in 1997). Industry was a distant second at 20% of total oil product demand in 2011. Its share has been relatively constant over the past decade.

Figure 4.10.2 Oil consumption by sector, 1973-2011



The trend of decreasing oil consumption is expected to continue, with the Association of the German Petroleum Industry Association (MWV) forecasting a 14% decrease in oil consumption for the period from 2010 to 2025. Key factors influencing the demand outlook include the promotion of biofuels and alternative fuels, energy taxation levels and efficiency standards for buildings and cars.

Figure 4.10.3 Oil demand by product, 1998-2012



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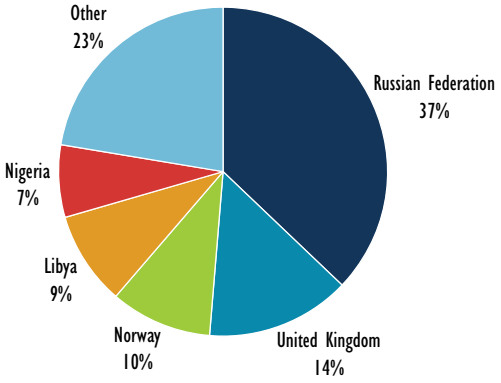
Imports/exports and import dependency

Germany's total oil imports were 2.6 mb/d in 2012. Imports included 1.9 mb/d of crude oil and 713 kb/d of products (420 kb/d of which was middle distillates and motor gasoline). Germany also exported around 386 kb/d of crude and products in 2012. The country has relatively diversified crude import sources, with the Russian Federation accounting for 37% of imports, the United Kingdom for 14% and Norway and Libya for 10% and 9% respectively in 2012. Fully 54% of refined product imports came from the Netherlands, followed by 17% from Belgium and 8% from Russia.

Figure 4.10.4 Crude oil imports by origin, 2012



Oil company operations

Germany has a highly deregulated and competitive oil market. A large number of companies operate in the German oil sector, including a large number of independents in the refining and retail sectors. The German government does not have an ownership stake in any of the companies operating in the oil sector.

Oil supply infrastructure

Refining

Germany has one of the largest refining capacities in Europe and is among the largest oil refiners in the world. As of the end of 2012 Germany had 13 refineries with a total crude oil atmospheric distillation capacity of 2.1 mb/d – or 104.4 million tonnes per year (Mt/y) – according to government figures.

German refining capacity has undergone some rationalisation in recent years. This is driven partly by changing local market conditions that have resulted in a decline in demand for gasoline and domestic heating oil. High crude oil prices and the changing structure of global refining have also increased pressure on refining margins.

One significant development in the rationalisation of German refining capacity was the decommissioning of the ConocoPhillips-owned Wilhelmshaven refinery at the end of 2010. With a capacity of 272 kb/d (13.5 mt/y), the refinery was the second largest in Germany at the time and chiefly produced for export. The site remains in use for storage of refined products.

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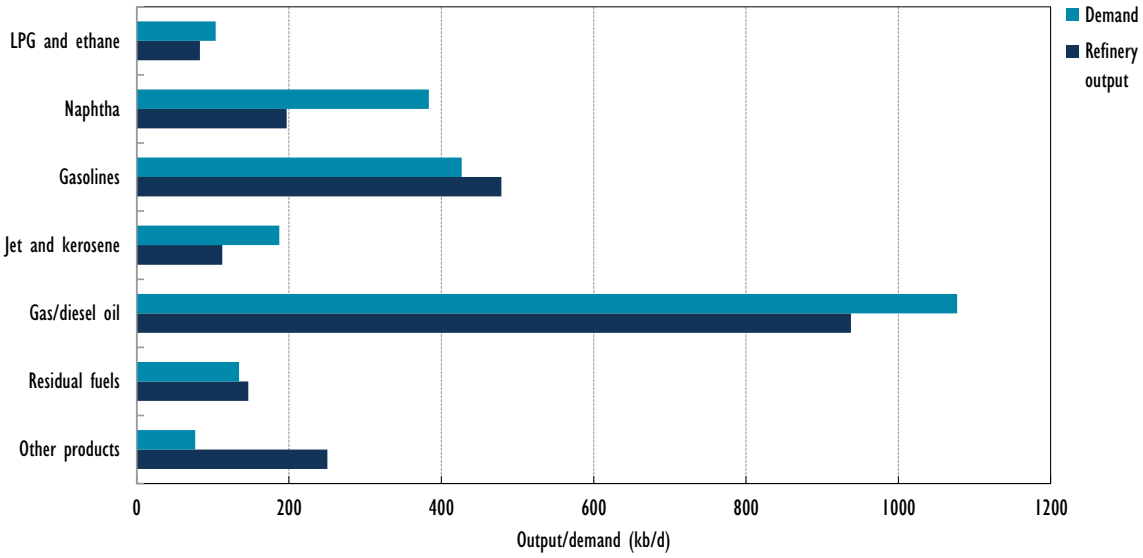
Figure 4.10.5 Refinery output vs. demand, 2012



Although total German refinery output is only slightly lower than domestic oil product demand, there are a number of imbalances which require significant imports of some products and the export of others. For example, Germany has been a net importer of diesel since 2010, and in 2012 had a 139 kb/d gas/diesel oil deficit and an overall middle distillates deficit of 230 kb/d. Conversely, the industry had a gasoline production surplus of 80 kb/d in 2012 and has been a net exporter of gasoline fuels and gasoline components since 2004. Germany's net product imports stood at 330 kb/d in 2012.

Demand for diesel increased by 30.9% between 2003 and 2012 while demand for gasoline dropped by nearly 29% during the same period.

Ports and pipelines

Crude oil is imported into Germany through four cross-border pipelines and four main sea ports.

The four cross-border pipelines – which transport oil from Russia, the Netherlands, France and Italy – had a combined throughput in 2012 of 1 294 kb/d (64.1 Mt).

With regard to Germany's oil ports, three are located on the North Sea (Wilhelmshaven, Brunsbüttel and Hamburg), and one other (Rostock) is on the Baltic Sea. The most important oil port for Germany is Wilhelmshaven which has three unloading facilities – two with a maximum capacity of 12 000 m^3 per hour and one with a maximum capacity of 16 000 m^3 per hour.

After unloading, the oil is processed in refineries near these ports or by inland refineries connected to the ports by pipelines. Four domestic pipelines (with a combined throughput of 484 kb/d (24 Mt) in 2012) connect Wilhelmshaven, Brunsbüttel and Rostock to several refineries.

All the crude oil pipelines are privately owned and operated by oil companies.

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Refined oil products are also imported into Germany through four sea ports (one in Bremen plus three of those also used for crude imports) and one product pipeline. The product pipeline runs from Rotterdam and has an annual import capacity of approximately 261 kb/d (12.8 Mt).

Germany also has four cargo ports with infrastructure for product imports. One of these, Bremen, is used solely for product imports. There are also a number of storage sites with anchoring berths in German coastal and riverside towns.

Storage capacity

Germany has an oil tank storage capacity of around 414 mb (65.9 mcm), 173.5 mb (27.6 mcm) of which is stored in caverns (as of the end of 2012).

EBV owns four cavern facilities consisting of 58 caverns in total and, additionally, holds contracts for storing in third-party caverns. The agency also has stored stocks in about 130 above-ground storage facilities.

Looking at the breakdown between crude and product, nearly half of current storage capacity is for crude and the rest is for intermediate and finished products. Refineries account for around one-third of total capacity, in addition to numerous other companies active on the market that collectively account for the other two-thirds of the country's oil storage capacity.

Decision-making structure

The Federal Ministry for Economic Affairs and Energy (BMWi) has the lead responsibility within the federal government for contingency planning and emergency measures. The Ministry's Director-General for Energy Policy is the German delegate to the IEA Governing Board. Decisions on the release of stocks from the German Stockholding Agency (EBV) are prepared in the department of the Director-General for Energy Policy and are taken up by the federal minister of the BMWi. Depending on the nature, cause, severity and history of an emergency, the federal chancellery and other selected ministries (e.g. the Federal Foreign Office, the Federal Transport Ministry) may also be consulted before the decision is taken to release stock. A maximum of 24 hours is required for this decision-making process during an IEA collective action.

The actual release of emergency stocks is authorised under the Oil Stockholding Act by means of an ordinance issued by BMWi. BMWi has a model text for a release ordinance available for immediate use. In the future, release ordinances will be published in the online *Federal Gazette*; it will only take three working days from a release decision until the entry into force of the release ordinance – and therefore until stocks can be made available to industry.

When stocks are released, the BMWi activates its national emergency strategy organisation (NESO) and consults the NESO's Crisis Supply Council (KVR) on issues of implementation, such as the breakdown between crude oil and the individual products of the quantity of supply released. The German NESO is based on close co-operation between the government, the stockholding agency, the EBV and industry for the purposes of crisis management. Key players include the BMWi, the Federal Office of Economics and Export Control (BAFA), EBV and the NESO's Supply Co-ordination Group (KGV), which is made up of supply experts from the oil industry and trade enterprises.

In the absence of a crisis the NESO office may co-ordinate regular emergency response exercises with the participation of BMWi, BAFA, EBV and KGV. Both national and international supply disruption scenarios are considered.

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Stockholding structure

The majority of Germany's stocks are held by the EBV. Since 1998, EBV has had sole responsibility for fulfilling Germany's 90-day stockholding obligation. The Oil Stockholding Act 2012 stipulates that EBV shall constantly maintain stocks of oil and petroleum products at a level which corresponds to a minimum of 90 days of net imports. The remainder of the stocks held in Germany are commercial stocks. There is no statutory obligation on industry to hold stocks for emergency purposes, so industry stocks are held solely for commercial purposes.

Crude or products

The different types of stocks held by EBV are: crude oil, gasoline, diesel fuel, light heating oil and kerosene-type jet fuel. The majority of above-ground EBV stocks are stored commingled with commercial stocks, while the storage of the agency's belowground stocks is segregated. The caverns mainly contain crude, and the above-ground facilities mainly contain product.

Location and availability

Germany has a convention of regionalisation in conjunction with the 90-day stockholding obligation. To meet this so-called regionalisation rule, the EBV holds stocks of finished products in each of Germany's five supply regions to ensure that it is capable of meeting a minimum of 15 days' demand for each region if required. The rationale for this is to prevent logistical bottlenecks which could occur if all emergency stocks were stored centrally.

All EBV stocks are fully available at all times.

Monitoring and non–compliance

BAFA monitors the fulfilment of the stockholding obligation. Here, the Oil Stockholding Act stipulates that the EBV must regularly provide the BAFA with the necessary data on stocks and must provide other information as required.

The EBV reports to BAFA on a monthly basis in the form of a standardised oil questionnaire detailing its purchases and sales, the stocks it owns, and delegations. BAFA also has the right to demand additional information and documentation from the EBV in order to monitor compliance with the stockholding obligation. Administrative offences may be punished with a monetary fine of up to EUR 20 000.

Stock drawdown and timeframe

The Oil Stockholding Act stipulates that it must be possible to release all EBV stocks for consumption within 90 days in the case of petroleum products and components, and within 150 days in the case of crude.

Financing and fees

The operations of the EBV are fully funded by contributions from its members. The members of the EBV are those companies that import products subject to stockholding obligations into Germany or manufacture them in Germany. The products subject to this obligation (as of 1 April 2012) are: gasoline, diesel fuel, light heating oil and kerosene-type jet fuel.

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Other measures

Demand restraint

Germany has both light-handed and heavy-handed demand restraint measures that it can deploy in an emergency.

The legal basis for demand restraint measures and for various other interventions in the oil market is the Energy Security of Supply Act 1975. A declaration by the federal government that the energy supply is endangered or has been disrupted is normally required before demand restraint measures can be implemented. To ensure that demand restraint measures can be implemented as quickly as possible if needed, a draft ordinance establishing a danger or disruption to Germany's energy supply has been prepared in advance. However, if the measures are being implemented to meet Germany's obligations under the International Energy Program (IEP), a government declaration is not required.

Intervention on the basis of the Energy Security of Supply Act must be proportionate to the disruption to supply, and be as light-handed as possible. Besides demand restraint measures such as speed limits, driving bans, etc., statutory ordinances could be enacted with rules on production, transport, storage, distribution, use and maximum prices of oil and oil products. However, Germany has a preference for stock releases before using demand restraint measures.

Fuel switching

Fuel switching also has limited application in Germany. In the case of electricity, only 1.3% of gross electricity generation was based on oil products in 2012 according to government figures.

In the case of the transport sector, almost all the sector's energy requirements are met using gasoline and diesel fuel. In principle, there is some limited potential for substituting fossil diesel with biodiesel in the short term. The production capacity of Germany's biodiesel manufacturers is roughly 4.9 Mt per year, which is well above current domestic consumption of 2.48 Mt per year.

Overall, Germany has only very limited possibilities for reducing oil consumption in the short term by fuel switching. Consequently, no legislation or policies are in place to promote short-term fuel switching in place at this time.

Other

No other emergency measures exist beyond those discussed.

Gas

Market features and key issues

Gas production and reserves

According to IEA figures, the country's natural gas production in 2012 was 12.3 bcm, down from around 13 bcm in 2010 and 19.85 bcm in 2005.

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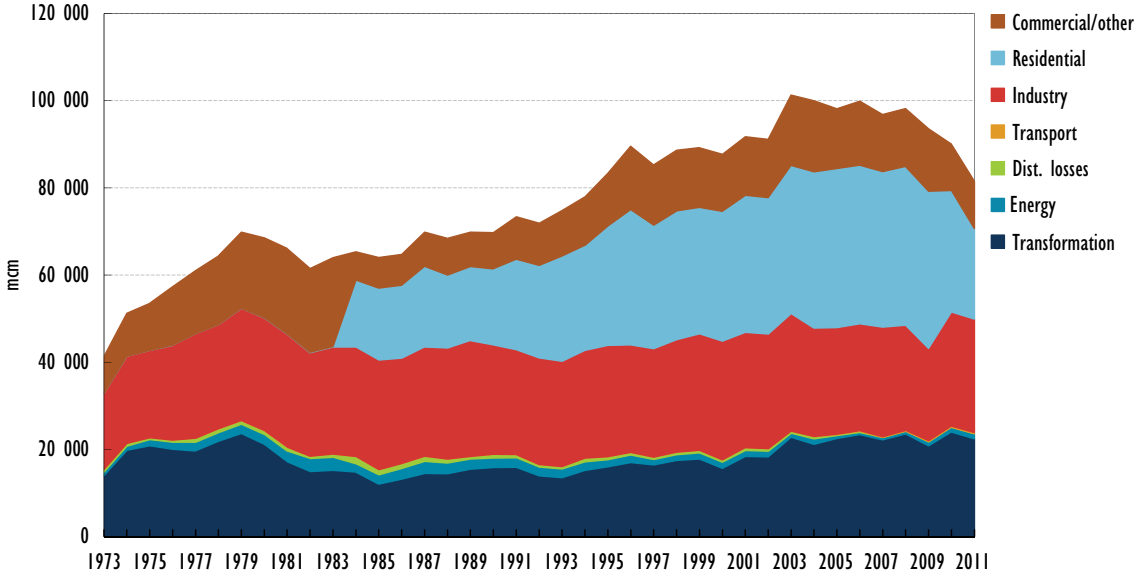
According to government estimates, domestic production is expected to decline by an average of 5% per year in the coming years. However, this does not take into account possible unconventional natural gas production in the future. The legal basis for the extraction of conventional and unconventional gas is the Federal Mining Act. There are no state incentives for any form of natural gas production.

Gas demand

Natural gas demand in Germany has declined by more than 11% since 2005. Demand was 87.2 bcm in 2012, up from 81.5 bcm in 2011 but down from 90 bcm in 2010 and 98.2 bcm in 2005. In 2011 the industry sector represented about 32% of total gas consumption, while the transformation and residential sectors represented 28% and 25% respectively. Significantly for energy security considerations, natural gas demand in the winter months is up to three times higher than in summer.

Figure 4.10.6 Natural gas consumption by sector, 1973-2011



According to government-commissioned analysis, the total consumption of natural gas in Germany is expected to continue to decline over the long term. However, conversely, the share of natural gas in Germany's TPES is expected to rise in the medium term (to 24% by 2025). The projected decline in total natural gas consumption is largely thanks to energy efficiency improvements and savings in various areas such as district heating. The government expects this decline to cancel out a likely increase in natural gas use for electricity generation.

Gas import dependency

The share of natural gas in the country's TPES was 22% in 2012, the same share as in 2011 and 2010 but down from 24% in 2005. Approximately 86% of Germany's natural gas demand is met through imports. Only 14% is produced domestically and domestic production has declined continuously in recent years.

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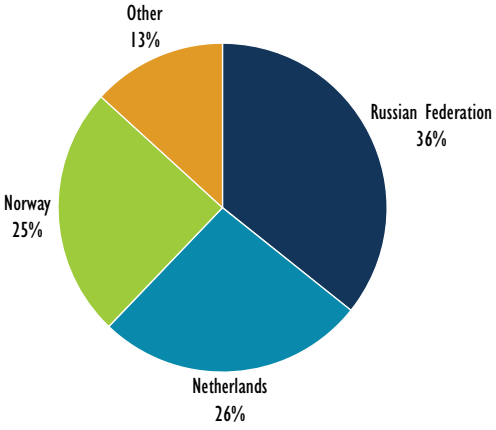
Figure 4.10.7 Natural gas imports by source, 2012



Germany's natural gas imports are geographically relatively diversified. In 2012 the biggest import source was Russia, which supplied 36% of natural gas imports, next was the Netherlands with 26% and Norway with 25%. Germany has no LNG infrastructure, so all the country's natural gas imports are supplied through a number of cross-border pipelines. However, some German companies have booked capacity in overseas LNG terminals, e.g. E.ON Ruhrgas has contracted 3 bcm a year in Rotterdam, the Netherlands.

The government expects that LNG will become an increasingly important source of natural gas for Europe in the future, so it considers access to LNG terminals to be important. For this reason it also encourages German companies to purchase regasification capacity in LNG terminals in neighbouring countries, and to buy LNG volumes from new suppliers. E.ON Ruhrgas had plans to build an LNG terminal in Germany but there was insufficient long-term interest for it to be commercially viable. However, there is a permitted site for an LNG terminal in Germany so it remains a possibility for the future.

Because of its comprehensive cross-border pipeline infrastructure and its central location within Europe, Germany is becoming an important natural gas transit hub, with significant amounts of natural gas from Russia and Norway transiting the country for delivery to other markets. Over the past five years the country has improved its gas market by implementing an entry/exit system in compliance with European Union regulations, reducing the number of market areas to two, and substantially improving competition and price formation in the markets – making the market more liquid.

Gas company operations

The natural gas industry in Germany consists of a production tier, three main market or trading tiers, transport system operators and natural gas storage companies.

Gas supply infrastructure

Ports and pipelines

Natural gas is imported into Germany exclusively by cross-border pipelines. There are a large number of these pipelines, bringing gas from Norway, Russia, the Netherlands, and to a lesser extent from Denmark and the United Kingdom.

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Natural gas deliveries from Norway reach Germany via three pipelines – Norpipe, Europipe I and Europipe II – with a total combined capacity of 54 bcm. Gas deliveries from Russia reach Germany via three pipeline networks – Nord Stream (since November 2011) with an initial capacity of 55 bcm, Yamal with a 33 bcm capacity, and the Ukraine pipeline system with a total capacity of 120 bcm. Some of the gas from both Norway and Russia transits Germany to other countries in Europe.

Natural gas (L-Gas) from the Netherlands is also transported to Germany via four main pipelines (or interconnection points).

With regard to the domestic pipeline network, there are 14 TSOs in Germany. The largest of these is Open Grid Europe which has a 12 000 km pipeline network, followed by ONTRAS, the second largest TSO, with 7 200 km.

Storage

Germany has 50 gas storage facilities with a total capacity of 22.7 bcm. All the gas is stored in caverns or in porous rock storage facilities and there is potential for further expansion thanks to a favourable geological situation. Germany's natural gas storage facilities are owned by numerous private companies (E.ON Gas Storage is the largest), and are well dispersed geographically. In addition to this storage capacity, German firms also have access to natural gas storage in Haidach, Austria which has a capacity of 2.6 bcm.

More cavern storage facilities are in the planning stage or under construction (with a total additional volume of around 8.2 bcm). A porous rock storage facility owned by Storengy is also being planned in Behringen, with storage volume of 2.3 bcm and a working gas capacity of 1 bcm.

There are no compulsory natural gas storage requirements in Germany and no state-owned storage facilities. Operators of gas storage facilities must grant other companies access to their storage facilities and auxiliary services at a fair market price.

Emergency policy

There are no compulsory natural gas storage requirements in Germany, and no state-owned storage facilities. All natural gas stocks in Germany are held by private companies for commercial reasons.

In an emergency, the federal government has the responsibility for triggering Germany's natural gas emergency response measures by declaring a state of emergency. The lead agency for natural gas security is the Ministry of Economics and Technology (BMWi). BMWi is responsible for natural gas legislation and for emergency response co-ordination at the national and EU level. The regulatory authority, with responsibility for implementation of non-market-based emergency response measures during a natural gas supply emergency, is the Federal Network Agency.

Natural gas emergency policy at the regional level also involves the *Länder* (regional governments) and municipal energy suppliers. The *Länder* have responsibility for implementing some aspects of non-market-based emergency measures in conjunction with the Federal Network Agency.

In the event of a natural gas emergency, certain groups of customers are protected from interruption to their natural gas supplies. These protected customers represent 50% to 60% of demand. Protected customers are defined as households and district heating installations delivering heating to households.

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Another important development with regard to gas emergency policy in Germany has been the implementation of EU Regulation 994/2010.

Emergency response measures

As stated above, the Energy Security of Supply Act permits the enactment of ordinances to restrict the sale, purchase or use of goods (i.e. demand restraint), both in terms of quantity and time, or permit them only for certain priority purposes.

Fuel-switching capacities are not included in German security of supply policy measures. Although some generators and larger industrial customers are equipped with fuel-switching facilities, only limited information is available on the overall volumetric potential of substitution effects in the case of an emergency. There are no regulations in place promoting, restricting or monitoring fuel-switching capabilities. The government expects companies to assume individual responsibility for backup solutions where necessary and possible in order to obtain a higher level of security of supply for their plant.

Companies equipped with fuel-switching capability would consider utilising this capacity in the case of a gas supply emergency. There are no restrictions to switching from natural gas to other fuels.

Interruptible contracts are concluded with industrial clients, especially with those who have fuel-switching capacity. In terms of the quantity of gas sold, a maximum of approximately 10% to 20% of contracts with clients are interruptible contracts. There are no government policies to encourage the uptake of interruptible contracts.

There are no other gas emergency policies in place, such as encouraging the ability to surge natural gas production.

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Greece

Key data

Table 4.11.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	16.9	5.9	1.8	2.3	1.9	1.6	0.9
Demand (kb/d)	314.1	399.2	423.9	372.4	351.0	317.9	274.6
Motor gasoline	56.1	75.7	90.7	85.8	77.3	69.3	-
Gas/diesel oil	107.0	144.3	160.6	133.4	131.6	109.2	-
Residual fuel oil	92.5	107.1	99.4	82.6	77.5	70.0	-
Others	58.5	72.0	73.2	70.6	64.6	69.3	-
Net imports (kb/d)	297.2	393.3	422.1	370.1	349.1	316.3	273.7
Import dependency (%)	94.6	98.5	99.6	99.4	99.5	99.5	99.7
Refining capacity (kb/d)	385.0	382.5	401.4	488.5	488.5	488.5	-
Oil in TPES (%)**	56	55	57	51	47	45	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.11.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	123	36	16	7	6	5	0
Demand (mcm/y)	123	2 052	2 842	3 850	4 665	4 354	4 901
Transformation	16	1 542	1 936	2 455	2 862	0	-
Industry	86	439	668	867	1 128	0	-
Residential	0	6	88	303	417	0	-
Others	21	65	150	225	258	0	-
Net imports (mcm/y)	0	2 016	2 826	3 843	4 659	4 349	4 901
Import dependency (%)	0.0	98.2	99.4	99.8	99.9	99.9	100
Natural gas in TPES (%)	1	6	8	12	15	14	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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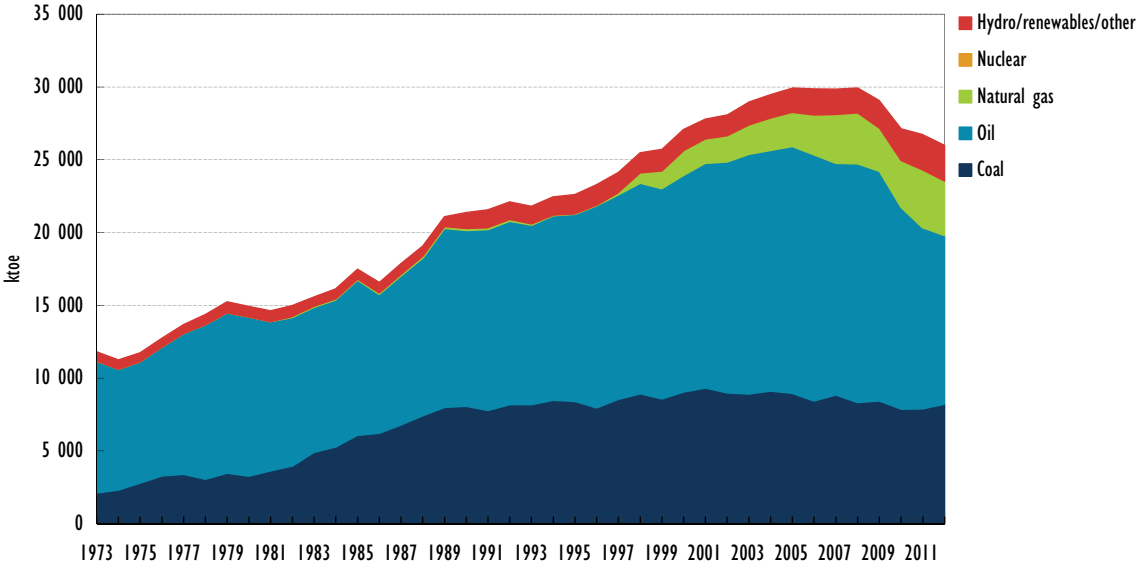
Figure 4.11.1 Total primary energy source (TPES) trend, 1973-2012



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Map 4.11.1 Oil infrastructure of Greece

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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Map 4.11.2 Gas infrastructure of Greece

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Country overview

Oil has been the dominant energy source in Greece, accounting for some 45% of the country's total primary energy Supply (TPES) in 2012. Oil demand peaked at 450 thousand barrels per day (kb/d) in 2007, and since then it dropped sharply to 318 kb/d in 2012. Almost all the crude oils used in Greece are imported. Most of the crude oil is imported from OPEC countries and the former Soviet Union (FSU) countries.

There are ten oil terminals in Greece, the majority located in the Attiki Area (Athens) and the remaining refineries in the Thessaloniki area. Six oil terminals can accept crude oils, of which four are located near the refineries. Nearly all inland transportation of crude oil and refined products is by ship and road. Products are also transported by rail in Greece, specifically to the power plants. Rail is also used to transport local products to the Balkans.

The four refineries, operated by two refining companies, have a total crude distillation capacity of around 490 kb/d. In 2012 some 56% of the refined product imports came from OECD Europe countries, while some 16% of refined product imports were imported from the Russian Federation. However, Greece's oil product exports significantly increased from 102 kb/d in 2004 to 245 kb/d in 2012. Greece is a net exporter of refined products.

The use of oil stocks held by domestic industry is central to Greece's emergency response policy, as Greece meets its entire stockholding obligation to the International Energy Agency (IEA) and the European Union by placing a stockholding obligation on industry. Importers of crude oil or oil products, as well as large end-users, are required to hold a volume of oil stocks equivalent to 90 days of their net imports made during the previous year. Companies liable to maintain emergency stocks can delegate up to 30% of their obligation to other companies or central stockholding agencies within the territory of the European Union. Greece does not hold public stocks and does not have any bilateral stockholding agreements with other IEA member countries, but emergency stocks are held on behalf of Cyprus[1] [2] according to agreements between the Cyprus Organisation for Storage and Management of Oil Stocks (KODAP) and Greek refineries. All oil stocks are held in the form of oil products, and commingled with commercial stocks.

The share of natural gas in the country's TPES has increased to 14% in 2012. Because of the growth in the demand for electricity and the subsequent construction of new gas-fired power stations, demand for natural gas steadily increased and in 2012 stood at 4.4 bcm (12 million cubic metres per day). Roughly three-quarters of gas is supplied from Russia and Turkey by pipeline, and the remaining portion is imported in the form of liquefied natural gas (LNG), largely from Algeria.

Key elements of Greece's overall policy on natural gas security are diversification of supply sources, establishment of market-based demand measures, reduction of the LNG delivery lead times during periods of high demand, signing of new contracts for gas supply as well as development of the natural gas transmission system (updating the existing LNG terminal, a new pipeline and an underground gas storage facility). The transmission system operator (TSO), DESFA, plays a major role in emergency planning and managing crisis situations. Interruption of gas supply for customers based on a

1. Footnote by Turkey: The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of the United Nations, Turkey shall preserve its position concerning the "Cyprus issue".

2. Footnote by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

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priority list, fuel switching at power stations and the use of gas reserves stored at the LNG terminal are foreseen as emergency response measures in a gas crisis.

In order for new gas-fired power producers to be granted with a production licence, they are obliged to hold at least five days of backup reserves of alternative fuel. Five thermal power generation units, which use gas as primary fuel, can switch to an alternative fuel.

Oil

Market features and key issues

Domestic oil production

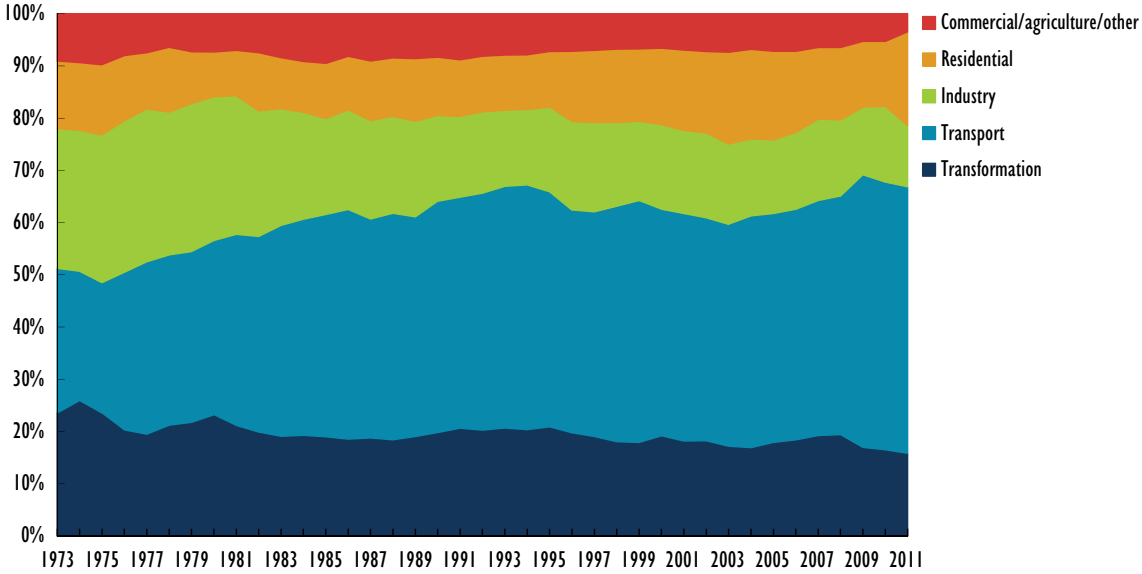
Greece has very little indigenous oil production (some 1.6 kb/d in 2012). Oil is produced from the Prinos offshore oil field in the Kavala Gulf in the northern Aegean Sea.

Oil demand

Oil demand in Greece increased from 383 kb/d in 2000 to 450 kb/d in 2007. However, having peaked in 2007, the country's oil demand sharply decreased to 318 kb/d in 2012 with an annual compound decrease rate of almost 7%.

Transport consumed 51% of Greece's total oil demand in 2011, followed by residential use (18%) and transformation/energy (16%).

Figure 4.11.2 Oil consumption by sector, 1973-2011



In terms of oil demand by product, demand for motor gasoline decreased 18% in the period between 2003 and 2012, while demand for diesel slightly increased by 2% in the same period. Demand for heating oil/other gasoil recorded a significant decrease from 127 kb/d in 2003 to 66 kb/d in 2012, while demand for residual fuels also dropped by 31%.

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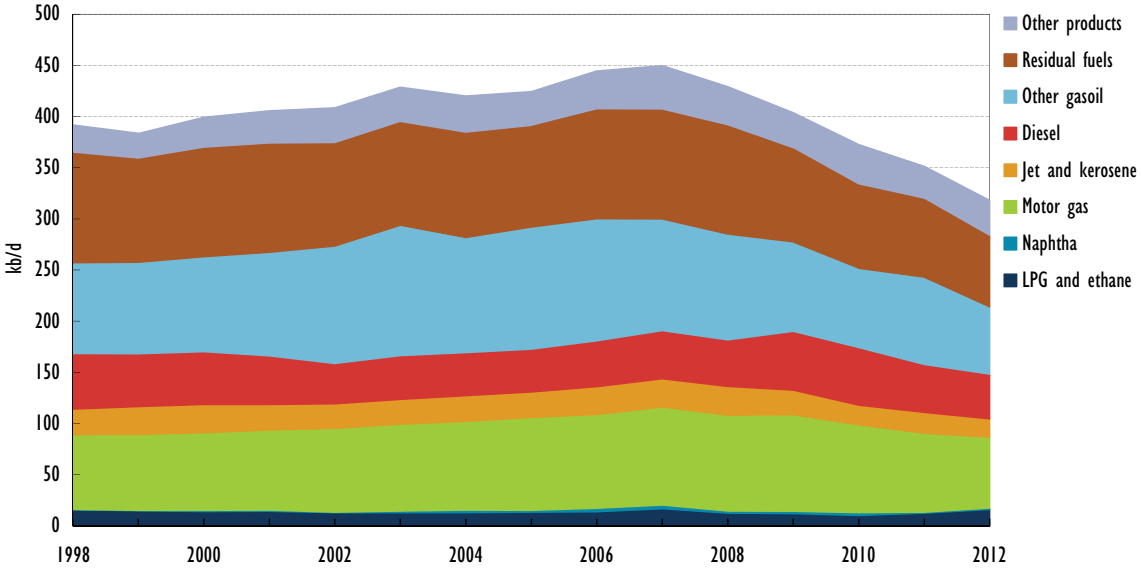
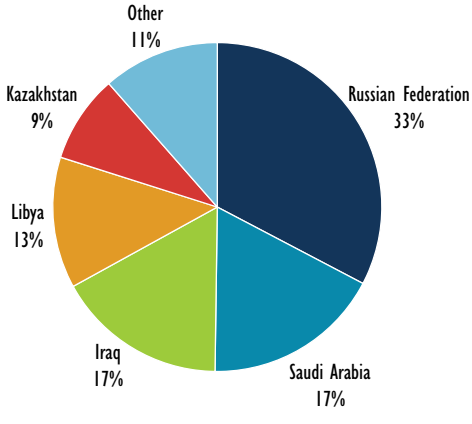
Figure 4.11.3 Oil demand by product, 1998-2012



Imports/exports and import dependency

In 2012 Greece imported 545 kb/d of oil, which consisted of 419 kb/d crude oil, 41 kb/d of natural gas liquids (NGLs) and feedstock, and 85 kb/d of refined products. Countries from the OPEC and the FSU have been major import sources of crude oil. By country, Russia was the largest supply source of crude oil, representing 33% of total imports in 2012, followed by Saudi Arabia (17%), Iraq (17%), Libya (13%) and Kazakhstan (9%).

Figure 4.11.4 Crude oil imports by origin, 2012



In 2012, roughly 56% of the refined product imports came from OECD member countries, mainly from OECD Europe, while some 16% of refined product imports for the same year were supplied from Russia.

Greece was a net exporter of refined products in 2012, exporting 245 kb/d of oil products. The destination of oil exports was mainly Turkey (22%), Singapore (9%), Lebanon (7%) and Libya (7%). Nearly 40% of total exports was gas/diesel oil in 2012.

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Oil company operations

Two companies operate in the Greek refining industry: Hellenic Petroleum and Motor Oil Hellas. The Greek state owns 35.5% of the Hellenic Petroleum capital but the company is to be fully privatised in the coming years. Over 20 trade fuel companies operate in Greece, with six of them covering almost 70% of inland consumption.

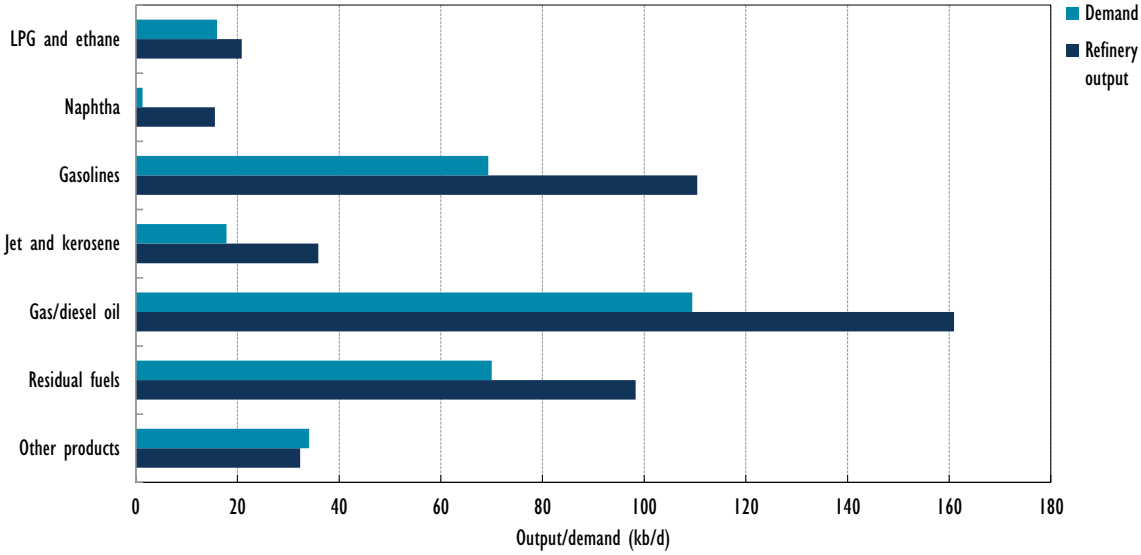
Oil supply infrastructure

Refining

The four refineries in Greece have a total crude distillation capacity of around 490 kb/d. Roughly two-thirds of this capacity is owned by Hellenic Petroleum, including two refineries located in the Athens area and a third near Thessaloniki. The fourth refinery, owned by Motor Oil Hellas, is located in Corinth. Refineries have completed extended upgrades, increasing their Solomon Composite Process Complexity Index, which makes them among the most modern and profitable in Europe.

In 2012 the four refineries processed over 22 million tones (Mt) (around 440 kb/d) of crude oil, with an overall capacity utilisation rate of almost 85%. In 2012, the refined product output totalled 474 kb/d. The composition of production was gas/diesel oil (34%), motor gasoline (23%), residual fuel oil (21%) and liquefied petroleum gas (4%).

Figure 4.11.5 Refinery output vs. demand, 2012



With decreasing domestic demand, in principle, Greek domestic refinery production is sufficient for meeting oil demand in the country; this permits extended exports mainly to countries around the Mediterranean.

Ports and pipelines

There are ten oil terminals in Greece, seven located in the Attiki Area (Athens) and the remaining three in the Salonica area. Six oil terminals (Aspropyrgos, Elefsina, Thessaloniki, Aghioi Theodori, Pachi (Megara) and Agia Triada) receive crude oil; four of these terminals are located near the refineries.

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Greece has two oil pipelines. The first, a 220-km-long, 16-inch crude pipeline with a capacity of 50 kb/d, links the Thessaloniki port in Greece with the Octa refinery in the Former Yugoslav Republic of Macedonia (FYROM). It is owned and operated by Hellenic Petroleum. The second, a 53-km-long, 10-inch Jet A-1 pipeline with a capacity of 42 kb/d, connects the Aspropyrgos refinery with Athens International Airport.

Except for jet fuels supplied to the Athens airport, nearly all inland transportation of crude oil and refined products is by ship and road. Products are also transported by rail in Greece, specifically to the power plants. Rail is also used to transport oil products to the Balkans.

An international pipeline project is being proposed for transporting Russian and Caspian oil from the Bulgarian Black Sea port of Burgas to the Greek Aegean port of Alexandroupolis. This 300-km pipeline, with a capacity of 0.7-1 mb/d, would be an alternative export route for Russian oil by bypassing the Bosporus Straits.

Storage capacity

Greece possessed a total storage capacity of 59.7 mb (9.5 mcm) used for industry operations and mandatory industry stocks in 2012. Crude oil storage accounted for some 30% of the country's total storage capacity. All the storage facilities owned by refineries are certified tanks for emergency stocks. A part of the storage facilities is also used for maintaining stocks for third parties in the context of the European Directive 2009/119/EC, such as foreign companies with term/spot commercial storage agreements and clients who require oil storage capacity to obtain retailing licences under the existing Greek law (4123/2013).

Decision-making structure

The Severe Oil Disruptions Management Committee forms the permanent core of the Greek national emergency strategy organisation (NESO), which is supported by the Directorate of Petroleum Policy of the Ministry of Environment, Energy and Climate Change. The committee is chaired by the General Secretary of the Ministry of Environment, Energy and Climate Change, and it is composed of 15 members, including the president of the Regulatory Authority for Energy (RAE); representatives of the ministries of national defence, finance, economy, and transport; representatives from the three branches of the armed forces; and representatives of refineries and retail companies. The committee is usually convened every three months while it is authorised to draw up and submit an emergency action plan to the Minister of Environment, Energy and Climate Change. Once the plan is activated, it reports on the implementation of the measures taken.

The Directorate of Petroleum Policy plays an important role in preparing and implementing an emergency response plan and measures. The directorate collaborates closely with the IEA, the European Union, domestic industries and regional authorities. The directorate also collects and processes data on emergency stocks.

In the event of an oil supply disruption, extraordinary meetings of the Severe Oil Disruptions Management Committee will be held at the Ministry of Environment, Energy and Climate Change. The Minister for Environment, Energy and Climate Change is responsible for the political decision as to whether Greece will participate in a proposed IEA collective action or not, and will approve the emergency response measures proposed by the committee.

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Stocks

Stockholding structure

Greece meets its stockholding obligation to the IEA and the European Union by placing a stockholding obligation on industry. Importers of crude oil or oil products destined for the domestic market, as well as large end-users (such as power plants) are required to hold oil stocks with a volume equivalent to 90 days of their net imports made during the previous year.

Under the Greek stockholding regime, an entity that is required to hold emergency oil stocks may agree with a third party owning certified storage facilities for the safekeeping of the total or a part of their statutory emergency oil stocks, following authorisation by the Ministry of Environment, Energy and Climate Change. Such a contract should be for at least one year and dedicated exclusively to keeping the emergency oil stocks. The government intends to limit the minimum duration of such contracts to less than one year with the aim reinforcing in parallel the security of supply and the terms of competition.

The new law for oil stocks No. 4123/2013 has a provision for the establishment of a stockholding agency with the legal form of a limited non-profit company in line with the European directive. The decision on the creation of the new agency, to be signed by the president of the Hellenic Republic, is will be made in due course, while taking into consideration Greece's current financial situation.

Crude or products

Greece held some 32 mb of industry stocks at the end of April 2013, equal to 132 days of net imports in 2012. About 33% of total industry stocks were stored as crude oil, while the shares of middle distillates and of motor gasoline were 31% and 13% respectively.

Location and availability

Compulsory stocks are maintained within the Greek national territory but the new legal framework provides the possibility of keeping up to 30% of stocks in other EU member states. Greece has no bilateral stockholding agreements with other IEA member countries, although emergency oil stocks are held in the Greek territory on behalf of Cyprus[3] [4] Compulsory stocks held by industry must be maintained in storage facilities that have been certified as emergency stocks storage tanks. However, this does not mean that operational and commercial stocks must be kept separately. In practice, compulsory stocks are commingled with operational and commercial stocks.

Monitoring and non-compliance

The parties responsible for maintaining emergency stocks are required to submit monthly oil statistical reports to the Directorate for Petroleum Policy, no later than on the first business day following the 20th calendar day of every month. A ministerial decision authorises the Directorate of Petroleum Policy to undertake spot inspections of emergency stocks in certified tanks. Usually the quantities maintained by entities are cross-checked through official documents of the customs and tax authorities.

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Stock drawdown and timeframe

In the event of a disruption in energy supply, the use of oil stocks held by domestic industry would be central to Greece's emergency response policy. The Minister for Environment, Energy and Climate Change is authorised to decide on the release of compulsory industry stocks, based on the proposal of the Severe Oil Disruptions Management Committee. In case of an IEA collective action, the committee will draft a decision on the emergency response measures as well as on the manner and type of stocks to be released, and will propose this decision to the minister for final approval within 48 hours of the Notice of Activation under the Initial Contingency Response Plan of the IEA.

There are also several stock release procedures during local supply disruptions, including temporary or mandatory reduction of the stockholding obligation by category of products, tender and allocation of emergency stocks to specific categories of customers or to specific geographic areas in the country. The Severe Oil Disruptions Management Committee regulates the distribution of emergency oil stocks and supervises compliance with the plan and emergency measures.

In the emergency plan which was approved by the Cabinet in 2013, restrictions of oil product exports are provided for in case of only local disruptions, as in case of global disruptions the country is committed to facilitate supply of the international market.

Financing and fees

The government does not provide any financial support for obliged stockholders. The costs of compulsory oil stocks are financed by the companies operating in the Greek market, and thus implicitly passed on to consumers through market prices. The government may occasionally decide to set a ceiling for fees charged by storage companies to entities without enough storage capacity.

Other measures

Demand restraint

Under the legal framework, the Severe Oil Disruptions Management Committee may decide on the demand restraint measures to take and may supervise their implementation.

The emergency plan, approved by the Cabinet in 2013, includes a comprehensive list of possible measures that can be taken to reduce oil consumption in the short term. Promotion of the use of public transport, speed limit reduction, carpooling and lowering heating temperatures are envisaged as voluntary demand restraint measures, which are expected to be encouraged by information campaigns through mass media. Compulsory measures considered are driving restrictions, limited opening hours of service stations, and restriction of fuel supply to retail companies.

Fuel switching

Oil is used for electricity generation on many of the 200 inhabited Greek islands. However, none of the oil-fired power plants in the country possess fuel-switching capacity to alternative fuels, as natural gas is hardly available on the islands. There is no specific policy or legislation for the promotion of short-term fuel switching from oil to other fuels in an emergency.

Other

Given that Greece has very little indigenous oil production, surge production of oil is not considered an emergency response measure.

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Gas

Market features and key issues

Gas production and reserves

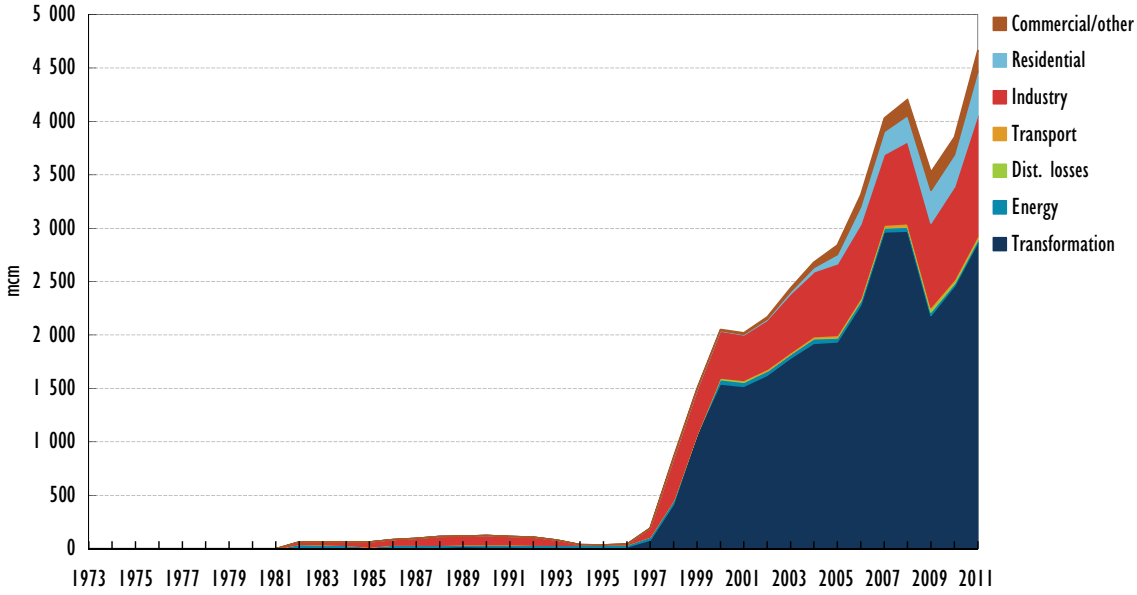
Greece's domestic production of natural gas is negligible. The South Kavala gas field, located in the Kavala Gulf of the Aegean Sea, produced 5 mcm in 2012.

Gas demand

Since the early 1980s natural gas demand has steadily increased and stood at 4.4 bcm (12 mcm/d) in 2012.

In 2011, transformation represented roughly 61% of total consumption, followed by industry (24%) and residential use (9%).

Figure 4.11.6 Natural gas consumption by sector, 1973-2011



The daily peak demand in 2011 amounted to 18.7 mcm/d, while the daily average demand in the year was 12.6 mcm/d.

Gas import dependency

Greece's total natural gas imports in 2012 were some 4.5 bcm, roughly three-quarters of which were supplied by pipeline and the remaining portion was imported in the form of LNG. Russia has been the principal source of natural gas imports since Greece began to import gas in November 1996. However, the share of Russian gas in total gas imports has gradually declined from 85% in 2005 to 60% in 2012, because of the increase in imports from Algeria and Turkey which accounted for around 16% and 15% of the total gas imports in 2012, respectively.

The Greek Public Gas Corporation (DEPA) has three long-term contracts for natural gas supply; with Russian Gazexport (2.8 bcm/y until 2015-2016), with Algerian Sonatrach

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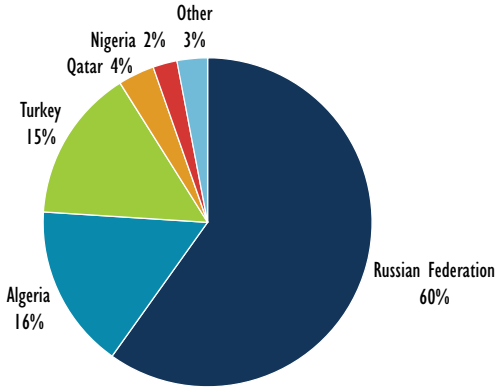
(0.5 bcm/y until 2019) and with Turkish Botas (0.7 bcm/y until 2021). Together they will supply a total volume of about 4.2 bcm per year.

Figure 4.11.7 Natural gas imports by source, 2012



Gas company operations

In accordance with the legislative framework on liberalisation of the natural gas market, in 2007 DEPA established the National Natural Gas System Operator SA (DESFA SA), a 100% subsidiary of DEPA. DESFA owns the existing gas infrastructure, and serves as the TSO as well as the LNG operator.

DEPA shares in three regional distribution system operators (EPAs: local gas distribution companies) by holding up to 51% of the share, while private investors hold the remaining 49%. Those companies are responsible for extending the urban networks, as well as supplying gas to domestic and industry consumers with annual consumption below 8.96 mcm per year. The consortium of Attiki Denmark participates in the EPA Attikis (Athens), while Eni participates in the EPA Thessalonikis and EPA Thessalias.

Gas supply infrastructure

Ports and pipelines

There are three entry points to the natural gas transmission system in Greece. The first entry point (with a maximum import capacity of 12 mcm/d) is located on the Greek-Bulgarian border, through which natural gas from Russia is imported by a pipeline through Ukraine, Moldova, Romania and Bulgaria. The second entry point (5.2 mcm/d) is on the Greek-Turkish border enabling gas imports from Turkey. The third entry point (12.5 mcm/d) is at Agia Triada, opposite the LNG terminal located on the island of Revithoussa in the Gulf of Megara.

According to the national preventive plan, these three entry points provide the Greek national gas transmission system with a maximum import capacity that, nevertheless, does not comply with the N-1 standard of European Regulation 994/2010, without robust demand restraint measures. While the missing entry capacity is estimated at 2 mcm/d for 2014, capacity upgrades at the entry points are planned.

Located in a strategic location for the delivery of Russian, Caspian and Middle Eastern gas supplies to Europe, Greece is involved in international gas pipeline projects, such as the Greek branch of the South Stream Pipeline, Interconnector Greece-Bulgaria (IGB) and Interconnector Turkey-Greece-Italy (ITGI).

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The most recent development includes the selection of Trans-Adriatic Pipeline (TAP) to deliver gas from Azerbaijan to Europe via Turkey, Greece, Albania and ending in Italy. When completed, TAP will be a major interconnector opening the Southern Gas Corridor for the supply of Europe with gas from the Caspian Sea.

The ITGI pipeline has also been chosen by the European Commission as a Project of Common Interest (PCI) although its implementation has been temporarily suspended. After the completion of these investments, Greece could emerge as an important natural gas player in the region.

The IGB project includes the construction of a cross-border and bi-directional gas pipeline about 181 km long (150 km in Bulgaria and 31 km in Greece), connecting the Greek gas network in the area of Komotini with the Bulgarian gas network. The annual capacity of the gas pipeline is foreseen to be up to 5 bcm.

Storage

Greece has some potential for natural gas storage, especially in the depleted field in South Kavala. However, as of 2013, the country's gas storage facility has been located only at the LNG terminal on the island of Revithoussa.

The combined storage capacity of the two LNG tanks in Revithoussa is 130 000 m^3 of LNG, which is equivalent to 80 mcm of natural gas. The full capacity of this storage facility is equivalent to around seven days of average gas demand in 2012. There is a plan to extend the LNG terminal in terms of both storage and regasification capacity. Construction of the third LNG tank was awarded by DESFA in 2013. It will increase the total storage capacity to 225 000 m^3.

There is also a plan to upgrade the existing send-out capacity from 1 000 m^3 LNG/h (or 14.8 mcm/d) to 1 400 m^3 LNG/h (or 20 mcm/d). The peak send-out capacity is planned to stand at 1 550 m^3 (or 23 mcm/d), increasing from 1 250 m^3 LNG/h (or 18.8 mcm/d). The port facilities are also to be upgraded to allow the berthing of LNG carriers with a capacity of up to 260 000 m^3, increased from 140 000 m^3.

Emergency policy

The key elements of Greece's overall policy on natural gas security are diversification of supply sources and routings as well as development of the natural gas transmission system. The RAE (National Regulatory Authority) carries out a risk assessment within the context of the implementation of the regulation to identify the most significant risks for the Greek National Natural Gas System (NNGS). Following a cost benefit analysis, based on the risk assessment, the RAE formulated the Preventive Action Plan which identifies a short-term strategy to address security of supply issues in the short term (up to two years ahead) and a medium-term strategy to provide increased security of supply in the medium term (three to six years ahead).

The short-term strategy will focus on several measures:

- reduction of LNG delivery lead times during periods of high demand
- agreements for supplementary gas which allows market participants to reach agreements with upstream parties for extra gas deliveries
- implementation of market-based demand-side measures and
- implementation of measures to enhance dual-fuel availability.

The medium-term strategy aims to comply with the N-1 standard and to reduce the residual risk posed by the most adverse crisis at the lowest cost for gas consumers.

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The medium-term strategy unfolds through the realisation of one more infrastructure project. The project could be one of the following: building of a new LNG terminal, realisation of an underground gas storage or a new interconnection linked with new supply agreements.

The country's TSO, DESFA, plays a major role in emergency planning and managing crisis situations that affect the NNGS. DESFA is exclusively responsible for the operation, maintenance, development and utilisation of the NNGS. Emergency response measures will include interruption of gas for customers based on the priority set by DESFA, fuel switching at power stations under the control of the electricity network TSO, and measures to ensure the availability of gas reserves in emergency cases.

Under the network code, DESFA declares an emergency gas situation and carries out an emergency response plan.

Emergency response measures

The Greek TSO prepared the emergency plan in the context of the Greek Law 4001/2011 and the provisions of EU Regulation 994/2010. The emergency plan provides for an emergency action team, sets procedures for responding to an emergency and lists measures that may be implemented during each of three crisis levels as defined in the regulation.

Under the provisions of Law No. 4001/2013, DESFA and customers are obliged to sign a contract for the interruption of natural gas supply ranked by priority. In case of a gas emergency, there is a specific ranking of natural gas interruption, and, according to this priority list, dual-fired power plants and big industrial customers are the first to be cut off.

DESFA may issue orders to interrupt gas supply not only to big industrial customers, but also to any other customer if it estimates that it is necessary for the effective operation of the natural gas grid. That course of action is intended to ensure that households and possibly small and medium-sized enterprises and district heating installations are protected.

DESFA has a load-shedding plan for the interruption of gas supply to electricity production units. The plan has 24 alternative scenarios for the interruption of gas supply at the three natural gas entry points.

Fuel switching at power stations is also envisaged as an emergency response measure in a gas crisis. In order to be granted a production licence, new gas-fired power producers are obliged to hold at least five days of backup reserves of dual fuel (i.e. either diesel at a storage facility on the power plant's premises, or LNG reserves at the Revithoussa LNG Terminal). Thirteen thermal power generation units, with a total capacity of 4 575 megawatts (MW), are connected to the national gas transmission system; five of them, with a combined capacity of some 1 972 MW, are able to switch from gas to oil in case of a gas disruption.

Around 16 000 m^3 of LNG (equivalent to about 10 mcm of natural gas) is available for peak shaving at the LNG tanks in Revithoussa.

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Hungary

Key data

Table 4.12.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	62.0	38.9	36.9	25.2	21.9	23.3	21.1
Demand (kb/d)	177.5	143.2	154.8	149.3	143.2	131.8	130.2
Motor gasoline	41.4	30.8	34.4	31.9	29.1	26.5	-
Gas/diesel oil	66.1	40.7	57.5	62.3	59.0	53.3	-
Residual fuel oil	30.3	26.8	4.3	2.4	1.9	1.5	-
Others	39.7	44.9	58.6	52.7	53.2	50.5	-
Net imports (kb/d)	115.5	104.3	117.9	124.1	121.3	108.5	109.1
Import dependency (%)	65.1	72.8	76.2	83.1	84.7	82.3	84
Refining capacity (kb/d)	0.0	232.0	161.0	190.3	190.3	190.3	-
Oil in TPES (%)**	30	27	26	26	25	24	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.12.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	4 874	3 194	3 028	2 900	2 766	2 234	2 447
Demand (mcm/y)	11 167	12 034	14 983	12 132	11 557	10 232	11 176
Transformation	2 703	3 057	4 352	3 693	3 401	0	-
Industry	4 707	2 112	2 000	1 671	1 711	0	-
Residential	2 059	3 771	4 869	4 003	3 667	0	-
Others	1 698	3 094	3 762	2 765	2 778	0	-
Net imports (mcm/y)	6 293	8 840	11 955	9 232	8 791	7 998	8 729
Import dependency (%)	56.4	73.5	79.8	76.1	76.1	78.2	78
Natural gas in TPES (%)	32	39	45	39	37	36	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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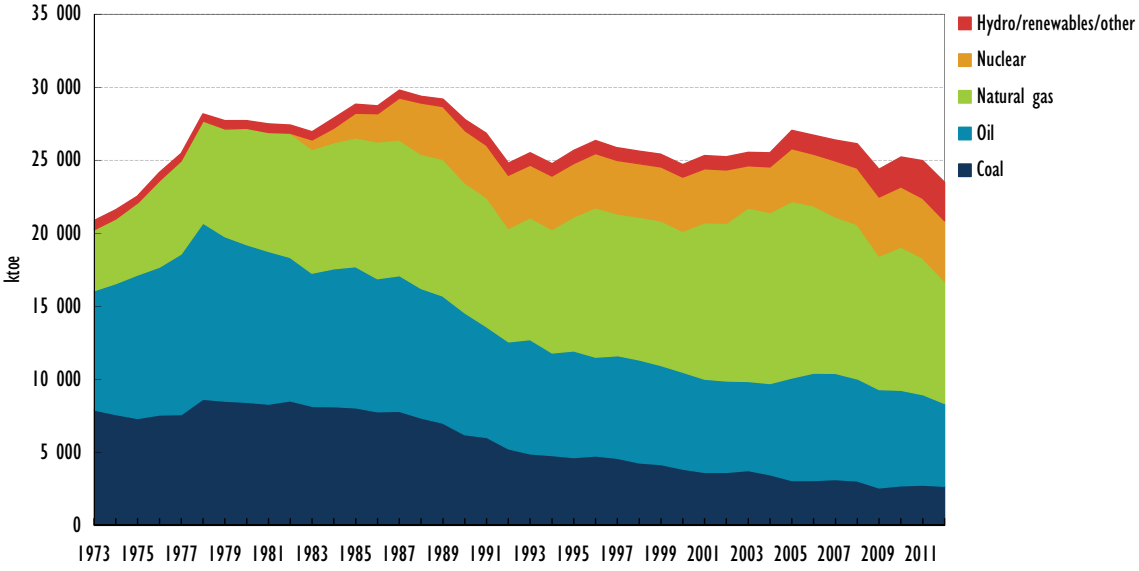
Figure 4.12.1 Total primary energy source (TPES) trend, 1973-2012



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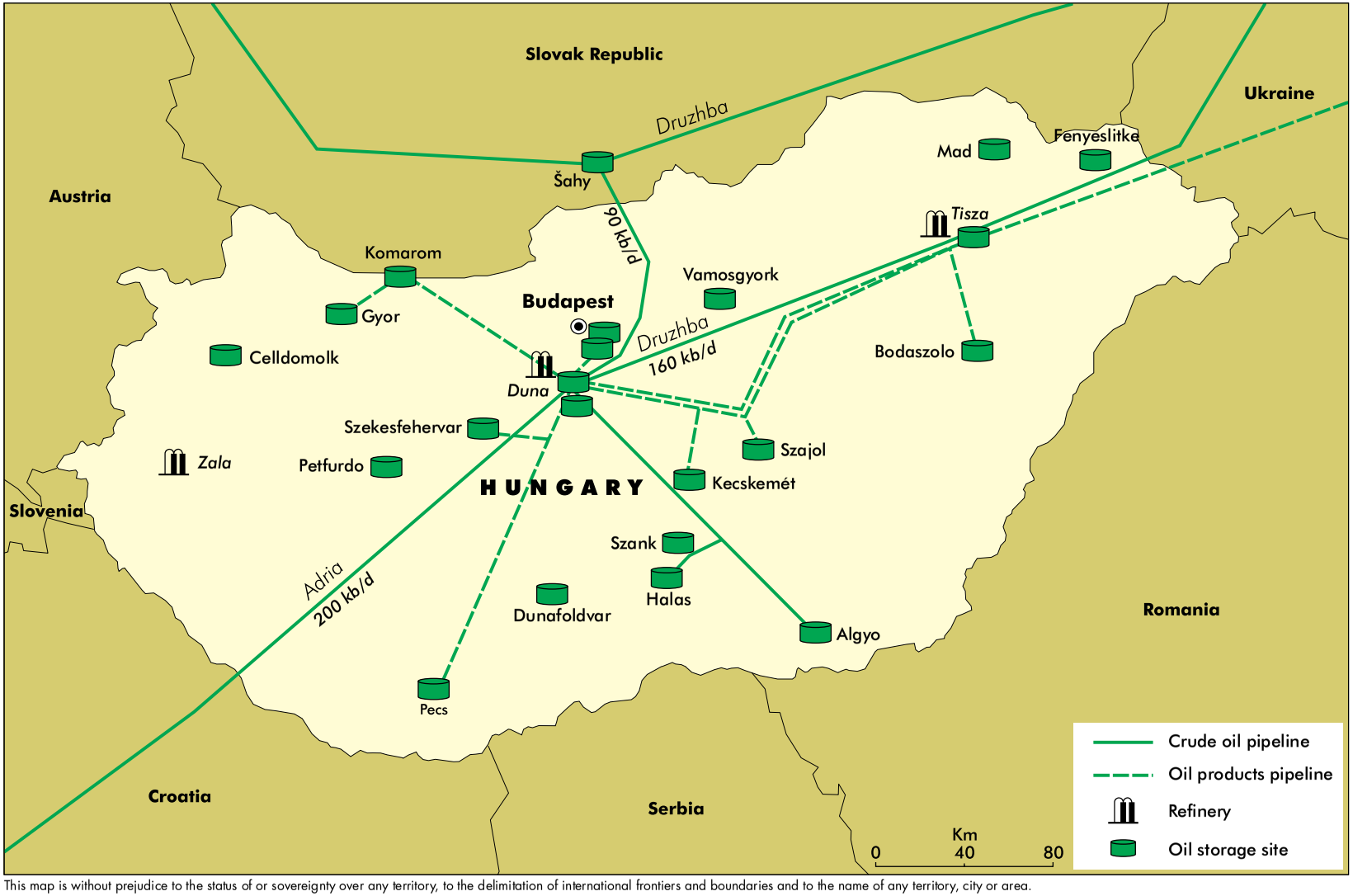
Map 4.12.1 Oil infrastructure of Hungary



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Map 4.12.2 Gas infrastructure of Hungary

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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Country overview

Hungary has little domestic oil or gas production and relies heavily on imports. the Russian Federation is the dominant supplier for both oil and gas, and Hungary is supplied by crude, product and gas pipelines.

Oil represents roughly one-quarter of the total primary energy supply (TPES) of Hungary and is expected to remain at this level until at least 2020. Domestic oil production will continue to decline, further increasing dependence on imports. Oil consumption as a whole has dropped incrementally from its peak in 2006 of 163 thousand barrels per day (kb/d) and stood at 131 kb/d in 2012. Nevertheless, demand for middle distillates remains strong. The share of oil in total energy consumption as a whole is gradually declining.

Natural gas demand has declined since its peak of 15 billion cubic metres (bcm) in 2005, but remains the fuel with the largest share of Hungary's TPES, standing at 36% in 2012. Gas demand dropped to 10.2 bcm in 2012 (from 13.1 bcm in 2008) owing to the economic crisis.

The use of publicly held stocks is central to Hungary's emergency response policy for both oil and gas. The Hungarian Hydrocarbon Stockpiling Association (HUSA) is entrusted with the public stockpiling of both oil and gas. HUSA was founded and is operated and financed by the Hungarian oil and gas industry. The government has special control rights over HUSA.

HUSA's public oil stocks are the equivalent of some 111 days of net imports (as of December 2012). When counted together with industry stocks, the total puts Hungary well beyond the International Energy Agency (IEA) minimum stockholding obligation of 90 days of net imports, with total stock levels standing at 152 days (as of December 2012). In an IEA co-ordinated response to a supply disruption, Hungary would respond with the release of public stocks.

Standing alone among its IEA peers (at the time of writing) Hungary has developed strategic gas reserves under government control. These were created in the aftermath of the January 2006 Russia-Ukraine gas crisis. Although these stocks reached the planned level of 1.2 bcm in early 2010, thereby covering around 40 to 45 days of average demand, the level has since been reduced to 0.76 bcm, equivalent to roughly 30 days of average demand.

Oil

Market features and key issues

Domestic oil production

Hungary has some oil reserves, mostly in the southeast of the country. Domestic crude oil production peaked in 1985, at 64 kb/d and is expected to continue its decline. In 2010 domestic production, including crude oil and condensate, amounted to 25 kb/d, or 13% of Hungary's total oil supply.

Oil demand

In 2012, Hungary's oil demand was 131 kb/d, down from 143.2 kb/d in 2011. While total oil demand in 2012 has decreased in comparison to 2000 and 2005 levels, oil use for transport has increased significantly, on average by 4.1% per year since 1995. In 2011 transport consumed 59% of total oil supply, and diesel alone accounted for 40% of oil product demand. Industry accounted for 24% of the total in 2011, a relatively constant share over the last decade. In contrast, oil use in the other sectors has declined markedly:

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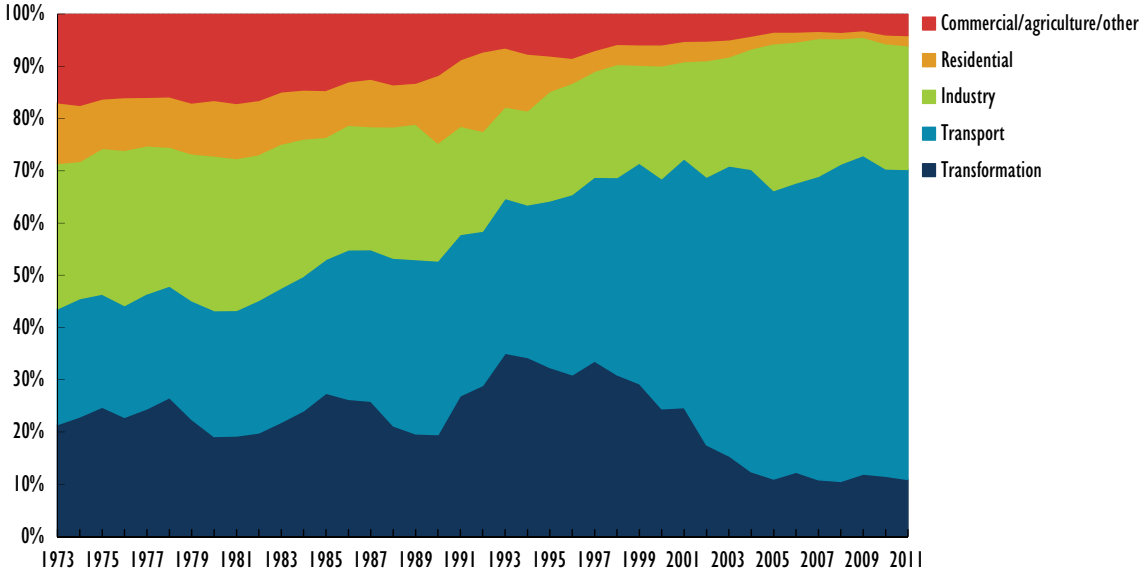
power generation, residential use and commercial services and the agriculture sector used 42% of oil supply in 1995, but only 17% in 2011. Of note, oil use for space heating is minimal.

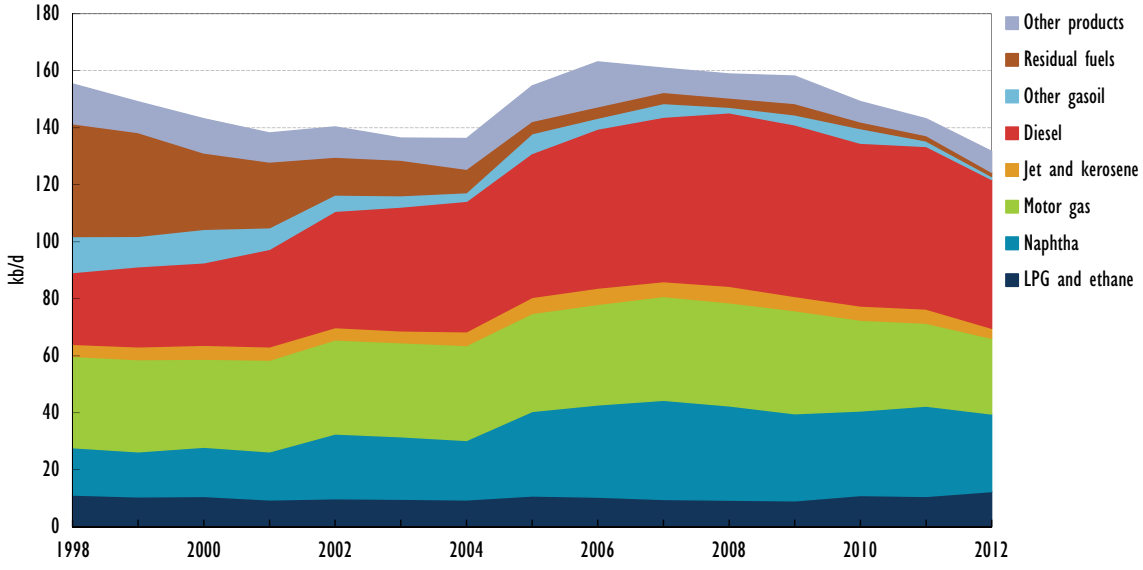
Figure 4.12.2 Oil consumption by sector, 1973-2011



The government expects the demand for oil products to grow by about 2% per year between 2010 and 2020. The key driver for growth is diesel use, increasing by about 3% to 4% yearly until 2020.

Dieselisation of the vehicle fleet is a gradual but continuing trend. At the end of 2009, 29% of all registered vehicles were diesel-fuelled while 71% were gasoline, but of all new vehicles registered in 2009, 50.5% were diesel-fuelled. Of note, vehicle ownership per capita stands at only 300 cars per 1 000 people, compared with the European Union average of around 500 cars per 1 000 people.

Figure 4.12.3 Oil demand by product, 1998-2012



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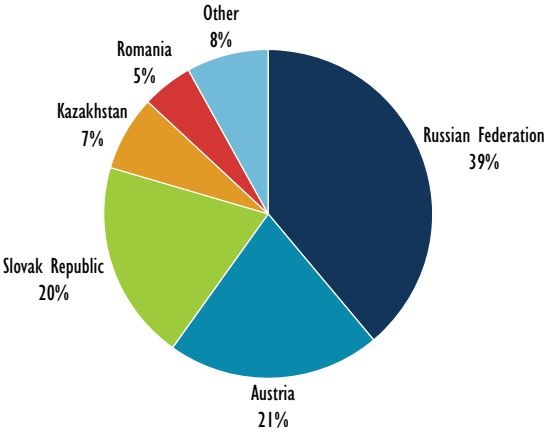
Imports/exports and import dependency

Approximately 82% of Hungary's crude oil supply in 2012 was imported, with all imports coming from Russia via the Druzhba pipeline system. Because of Hungary's declining domestic production, import dependency is expected to grow further.

Figure 4.12.4 Oil product imports by origin, 2012



Oil company operations

The Hungarian Oil and Gas Public Limited Company (MOL) is the main oil company in Hungary. It operates in both the upstream and downstream sectors. MOL is listed on the Budapest Stock Exchange and has a diversified ownership structure, consisting mainly of other energy companies, banks and foreign and domestic institutional investors. MOL and OMV of Austria are the largest wholesale companies in the region.

The retail market consists of numerous players. With 363 filling stations, MOL has the largest network. It is followed by Shell (249 stations), Agip (183), OMV (178) and Lukoil (75). In addition, there are some 600 white stations in Hungary, i.e. small private companies with just a few stations. The retail market consolidated from 2006, as OMV bought Q8, BP and Aral, while Agip bought Tamoil and ExxonMobil, and Shell bought Total and Tesco's supermarket stations.

Oil supply infrastructure

Refining

Hungary's refining industry supplies some 80% to 85% of oil products (including the output from MOL's Slovnaft refinery in the neighbouring Slovak Republic). The remaining oil products supplied to the market are imported. The largest source of imported product is Russia, with a large share of imported product also supplied from OMV's Schwechat refinery in Austria. Additional important product sources are Kazakhstan, Romania, Croatia, Belarus and Italy. Hungary has made notable efforts to diversify its oil product supply sources.

MOL is the owner of Hungary's three working oil refineries: Duna (Százhalombatta), Tisza (Tiszaújváros) and Zala (Zalaegerszeg). However, crude oil distillation is concentrated in the Duna refinery. Tisza's role is hydrofinishing gas oil and ETBE production, and bitumen is blown and blended at Zala. MOL supplies the majority of the domestic market's needs, but also sells its motor fuels, heating gas oil and bitumen to neighbouring countries in Central and Southeast Europe.

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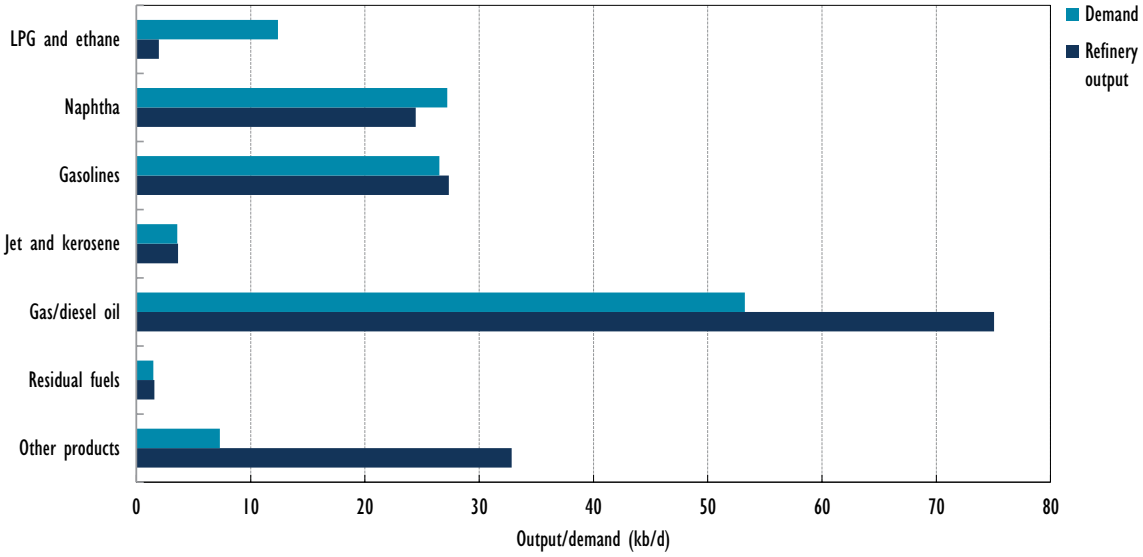
In 2012, the country's refined product output totalled 166 mb/d and the capacity utilisation rate of Hungary's refineries was 88%. The composition of production was gas/diesel oil (45%), motor gasoline (16%), residual fuel oil (1%) and naphtha (15%). Hungary's refineries produce sufficient amounts of diesel (75 kb/d), gasoline (27.3 kb/d), jet kerosene (3.6 kb/d) and residual fuels (1.5 kb/d) to meet local demand.

Figure 4.12.5 Refinery output vs. demand, 2012



Ports and pipelines

There is no oil port in Hungary, but there is the option to export and import refined products by barge from Komárom and Százhalombatta. A large proportion of product exports from MOL refineries are transported by barge on the Danube River.

The Druzhba pipeline system, originating in Russia and transiting Ukraine, is Hungary's main crude oil supply channel. The Druzhba I pipeline (built in 1961) has an entry point capacity of 70 kb/d (3.5 Mt/yr) and supplies Hungary from its northern border with the Slovak Republic. The Druzhba II (built in 1971) has a capacity of 160 kb/d (7.9 Mt/yr) and supplies Hungary from its eastern border with Ukraine. The pipeline terminates at the Duna refinery (via the Tisza refinery).

Hungary is also linked to the 'Eastern product pipeline' that transports product from Russia's refining centres via Ukraine. This enables MOL to purchase gasoil feedstock from Russia for further processing. There is no arrangement in place for purchasing other feedstock.

The Adria oil pipeline, with a capacity of 200 kb/d (10 Mt/yr) links the Duna refinery to the Croatian port of Omišalj. This pipeline was originally intended for the delivery of crude oil imports from the Middle East or Africa to Hungary but has mainly been used for transport in the opposite direction, transiting Russian crude oil to the Sisak refinery in Croatia. The Hungarian government indicates that in an emergency it would take around 30 days for the Adria pipeline to be reversed in order to transport crude oil from the Adriatic Sea to the Duna refinery. A further pipeline connection from the Duna refinery to Šahy in the Slovak Republic extends the Adria to the Slovak section of the Druzhba pipeline. This connection has a capacity of 90 kb/d (3.5 Mt/yr).

MOL operates 1 356 km of domestic product pipelines to supply the main depots in Hungary: Székesfehérvár, Pécs, Komárom, Szajol and Tiszaújváros.

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Storage capacity

Total storage capacity in Hungary stands at some 12.16 mb (of which 4.12 mb is for crude and 8.04 mb for products), spread over 10 sites.

The operating depot system has been downsized, the result of network optimisation. As of 2011 MOL has no plans to change the system in the near future, although some existing closed depots can be put back into operation within a relatively short time. Of note, there is no third-party access to MOL's terminals, even if they are unused.

Eight MOL depots serve as public storage terminals (customs warehouses) for finished products and other companies operate depots at other locations. Three crude storage tank farms include storage facilities for commercial and strategic stockholding purposes.

Crude oil stored at one of the facilities, Tiszaújváros, can be transported via pipeline to Százhalombatta. A few days' outage can be covered with existing storage facilities, and no expansion of storage facilities is planned by the industry.

Decision-making structure

Energy supply is the declared responsibility of the Minister of National Development in co-ordination with HUSA and the relevant stakeholders. Their responsibilities include oil security, maintenance and improvement of the emergency response system and co-ordination with the IEA.

The oil NESO is the key stakeholder body for emergency response and operates under the supervision of the minister. The political head of the system is the state secretary for energy, while the operational head is the deputy state secretary for energy together with the directors-general under his/her supervision. In a declared emergency, however, the NESO is directly led by the minister. The NESO works in close co-operation with HUSA's board of directors. The board includes: representatives of the Ministry of Public Administration and Justice; the Ministry of National Development; oil companies including MOL, Eni, Mabanaft and Shell; appointed expert members of certain partner ministries (e.g. the Ministry of Interior); the Hungarian Petroleum Association (MÁSz); and the Energy Centre.

The legal basis for Hungary's oil emergency response policy is Act No. XLIX/1993 on the Emergency Stockholding of Imported Crude Oil and Oil Products (amended in 1997 and 2004). It outlines the requirements in terms of emergency oil stockpiling held by HUSA and provides the Ministry of National Development with the statutory power to implement demand restraint or release strategic oil stocks in response to an IEA or European Union declared emergency. The Act is in line with the relevant European Directives (98/93/EC, 73/238/EC and 2006/67/EC). The roles and responsibilities of government ministries during an emergency are allocated in Government Decree No. 212/2010. (VIII.1) Korm.

Stocks

Stockholding structure

HUSA is responsible for meeting Hungary's stockholding obligations as a member of the European Union and the IEA. It thus maintains, on behalf of member companies, stock levels of no less than 90 days of domestic consumption of the three main product categories (gasoline, middle distillates and fuel oil). In practice, the agency holds levels in excess of the minimum requirement. All strategic stocks must be available for withdrawal within 48 hours of the government's order for release.

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Hungary has also signed formal bilateral stockholding agreements with Slovenia, Italy and Croatia. Hungary does not allow stock ticket arrangements for its IEA and European Union stockholding obligations, but it holds ticketed stocks for Italy and Slovenia, primarily of gasoil stocks.

Crude or products

HUSA holds 43% of its stocks in crude oil. The remainder is split between motor gasoline (19%), diesel (38%) and heating oil (for power plants, less than 1%).

Location and availability

Hungary would contribute to an IEA collective action by tendering stocks from HUSA's public reserves. Physically, stocks are held separately from industry stockholding. If a tender were to be held it would be location-specific, so delivery would be directly from the tank in which the stock is held.

Monitoring and non-compliance

Hungary's oil stocks remain comfortably above the IEA's 90-day requirement, the equivalent of 152 days of net imports in December 2012, of which 41 days were held by industry and 111 days are public stocks. Hungary consistently meets the IEA's 90-day obligation with its public stocks alone.

HUSA's activity is controlled by its members (market participants) and the government through voting rights exercised at the general meeting and by the board of directors.

All emergency stocks are owned by HUSA and are stored separately from commercial stocks. The Hungarian Stockpiling Act lays out strict controls on accounting and close physical monitoring. HUSA regularly conducts inspections of the operation of storage companies and facilities.

Stock drawdown and timeframe

In the event of a supply disruption, the drawdown of stocks is ordered by the minister, on the basis of consultations with the NESO members. As HUSA is a member of NESO, the drawdown process can be started immediately.

Following the declaration of an oil supply disruption, HUSA member companies have 48 hours to declare their quota (i.e. the amount they have the right to purchase from the stockdraw), after which those not exerting their right forego all access to the stockdraw. The minister then has the right to choose how to allocate any unclaimed stocks, either by awarding pre-emptive purchase rights to selected consumers or by asking HUSA to call for tenders from its member companies.

Physical deliveries are possible within 48 to 72 hours following a stockdraw decision.

Financing and fees

HUSA is an independent, not-for-profit company. It is financed by compulsory membership of all crude and oil product and gas traders in Hungary. Membership levies are proportionate to the percentage of oil and gas the company puts into circulation on the domestic market.

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Other measures

Demand restraint

Hungary has never resorted to demand restraint measures, and is unlikely to resort to such measures in a crisis. However, in the event of a crisis, the minister is entitled to take measures to restrict consumption in a decree issued jointly with the other ministers concerned in the regulation.

Since 1979, Hungary has had rules and legislation giving the minister responsible for energy wide-raging authority to impose demand restraint measures. If necessary, a parliamentary decision can also be prepared on the NESO's behalf. Hungary distinguishes three levels of demand restraint: light-handed, medium-handed and heavy-handed measures.

The light-handed measures can be executed within a few days and would result in a 2% to 4% reduction in consumption. They include:

- publicity to encourage fuel savings
- avoiding the use of cars for short distances
- reducing the temperature of public buildings
- encouraging a reduction of the temperature in dwellings.

The medium-handed measures would take one to two weeks to implement and would result in a 4% to 8% reduction in consumption (including the aforementioned light-handed measures). They include:

- introducing driving and speed restrictions
- prohibiting driving for one day a week or at weekends
- restricting the use of passenger cars based on registration numbers
- reducing the quantity of fuel that can be purchased at filling stations
- restricting the deliveries of oil products.

Heavy-handed measures include:

- the introduction of quotas on fuel oils for large customers (amounts to be determined by a crisis committee)
- retail quotas and restriction of fuel oil deliveries for small customers
- a restriction on the use of motor fuels by the chemical industry
- the introduction of rationing tickets for motor fuels in the private sector; the introduction of quotas on motor fuels in the public sector
- the allocation of quotas on motor fuels for the trading and services sector.

The impact of the heavy-handed measures has not been quantified and could take two to three months to have an effect.

Fuel switching

There is virtually no ability to switch from oil to other fuels, although there is a limited amount of fuel switching from natural gas to oil.

Other

Hungary has no potential for increased indigenous production in an emergency.

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Gas

Market features and key issues

Gas production and reserves

Domestic gas production met approximately 24% of total demand in 2011, with the remainder of demand met by imports, mostly from Russia. Domestic production has been in steady decline since 1990, when it stood at almost 4.9 bcm. In 2011 production stood at 2.7 bcm, and in 2012 it is estimated to reach 2.2 bcm. The country has proven reserves of 95 bcm, according to Cedigaz, corresponding to roughly 40 years of current level production. Gas production comes mostly from mature fields, but the government believes that production can be maintained at close to these volumes until around 2020. Thereafter, however, production is expected to decline considerably if no new resources are developed.

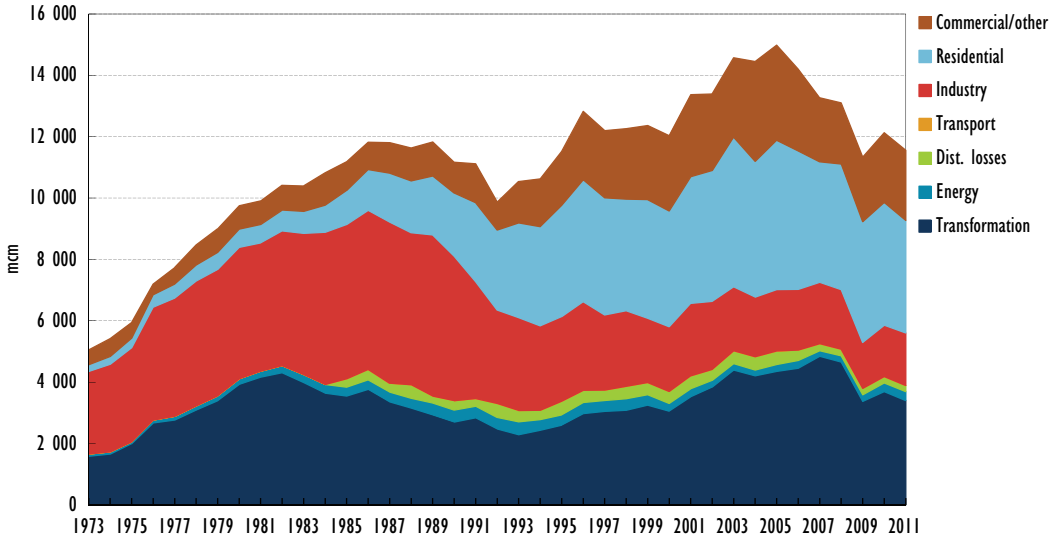
Hungary has unconventional gas resources – tight gas – but this potential remains very uncertain. Several companies, including MOL, ExxonMobil, and Falcon, are involved in unconventional gas exploration, for example in the Makó Trough and the Békés Basin. However, most activities are in the preliminary stages and it is too early to estimate if and when unconventional gas could reverse the declining production trend. The government is encouraging unconventional gas production with lower royalty rates (12%) than conventional gas production (up to 30%). However, the terms for new gas exploration contracts are determined on a case-by-case basis by the government.

Gas demand

Gas demand has been declining since 2005. It dropped by some 30%, to 11.5 bcm in 2011 (from 14.9 bcm in 2005) and is expected to stay at similar levels in the future.

The residential sector is the largest consumer of natural gas in Hungary, standing at some 32% of total gas demand in 2011. As such, the supplies of natural gas are of paramount importance in the cold winter months, as many homes depend on gas for residential use and heating. Equally important, the transformation sector accounted for around 30% of gas demand. The commercial sector accounted for 20% of gas demand, and industry accounted for another 15%.

Figure 4.12.6 Natural gas consumption by sector, 1973-2011



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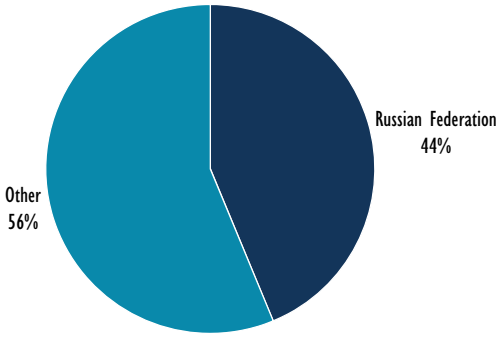
Gas import dependency

Hungary imports approximately 76% of its natural gas demand. Net imports of gas in 2011 amounted to around 8.7 bcm, down from 9.2 bcm in 2010 and 11.9 bcm in 2005.

While Hungary was until recently largely dependent on imports from Russia (in 2009 more than 80% of its imports came from Russia), recent years have seen a significant change in this trend. Imports from Western Europe and other sources have increased incrementally since 2008, as traders have taken the opportunity of cheaper spot prices for gas from this region. In 2011 only 65% of natural gas was imported from Russia and the estimates for 2012 show this figure to be even lower at 44%.

As of 1 July 2010, 20% of the import capacity is reserved for short-term capacity booking contracts.

Figure 4.12.7 Natural gas imports by source, 2012



Gas supply infrastructure

Ports and pipelines

Hungary's gas transmission network consists of 5 632 km of high-pressure pipelines, with 402 gas delivery points. The network includes five compressor stations with a total installed capacity of 135 MW.

Hungary imports most of its gas from Russia via Ukraine at Beregdaróc (56.3 mcm/d), but also small amounts via Austria at Mosonmagyaróvár (12.1 mcm/d). Hungary is planning to enhance its import capacity as well as diversifying its import routes and sources. Hungary is also a key transit country for Russian gas to southeastern Europe, and is looking to expand its general role as a transit country. Around 12 to 15 bcm are transported on Hungary's gas transmission network annually, of which some 4.25 bcm are reserved for transit through the grid.

This process of diversifying supply sources and expanding Hungary's role as a transit country includes the construction of the Romanian and Croatian interconnectors, preparation for missing links (Slovakian and Slovenian interconnectors) and future considerations of capacity upgrades for existing interconnectors. The cross-border connection between Hungary and Romania was completed in 2010 and the one with Croatia has been in operation since the beginning of 2011.

Storage

Gas storage is crucial because of the high dependence of Hungary's electricity sector on gas-fired power plants, and because of the high volumes of relatively inflexible residential demand. Hungary has five commercial storage facilities, with a total working

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capacity of 5.43 bcm and a withdrawal capacity of 72.0 mcm/d at the beginning of the winter months. All commercial storage can be accessed by third parties.

Following the supply interruption of January 2006, the Hungarian parliament approved a new law, Act No. XXVI, 2006 on Safety Stockpiling of Natural Gas, in February 2006. According to the act a strategic underground gas storage facility of 1.2 bcm was to be built, so as to provide Hungary with 40 to 45 days of autonomy if its main import source from Russia failed.

The stockpile aims to protect households as well as customers who cannot switch to other energy sources. HUSA and MOL established MMBF Zrt, a private limited company, to own and operate the storage facility, which was completed in 2010. The gas is owned by HUSA.

In June 2010, Hungary amended the legislation to allow for a reduction in the minimum strategic stockholding level, the level to be determined on a yearly basis by the minister.

Emergency policy

Hungary's natural gas emergency response measures for use in the event of an interruption to supplies are set in Government Decree No. 265/2009. (XII. 1.) Korm.

The Hungarian Energy Office (HEO) is the regulator for natural gas. It approves the network code which provides for transparent and non-discriminatory access to the network for all user groups. In practice, the regulator's powers are often limited to providing advice to the minister, who has the right to set system usage and connection tariffs and the price of "universal supply" (notably to households). The HEO co-operates closely with the Hungarian Competition Authority and the Hungarian Consumer Protection Authority. The parameters of their co-operation are detailed in a joint agreement which is reviewed every year.

The third European Union gas market directive (2009/73/EC) obliges EU member states to separate the transmission system operations of vertically integrated companies from their other operations. Hungary opted for the independent transmission operator option, and its parliament amended the Gas Act accordingly in January 2010. Consequently, the gas transmission owner/operator FGSZ remains 100% owned by MOL but is subject to heavy regulation and permanent monitoring to ensure non-discriminatory system operation.

In the event of a crisis, the TSO is responsible for operational crisis management. However, decisions regarding certain strategic questions may remain in the hands of the regulator or government. There are no specific emergency plans between the Hungarian TSO and neighbouring countries.

In the case of natural gas, the structure of the natural gas NESO is similar to the oil NESO, but the crisis committee includes partners from the natural gas industry such as the limited company FGSZ and the energy service provider E.ON, as well as other relevant authorities.

Emergency response measures

System operators are responsible for informing the regulator about any circumstance which could indicate a crisis. The regulator assesses the seriousness of the crisis and determines the rating of exceptionality (crisis level 1 or 2), and informs the minister who, in agreement with the crisis committee, formally determines the crisis level. Under crisis level 1, the system can be operated in line with the existing civil law contracts through a combination of restrictions and the use of strategic stocks. Under crisis level 2, the gas

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market cannot be operated in line with the existing civil law contracts and the remaining gas sources have to be managed by the TSO.

Any decision to release strategic gas stocks lies with the minister. HUSA is responsible for monitoring gas stocks and is responsible for ensuring that any stock release goes according to plan.

The Hungarian Natural Gas Law outlines demand restrictions that can be implemented in case of supply disruption, when there are no other applicable means for ensuring balance in the system. The responsible authorities are the minister, the HEO and the TSO. In a crisis situation, detailed rules are set up for all market players.

There is a priority list of consumers for whom supplies must be guaranteed, even in the event of a severe crisis (crisis level 2). Among the priority listing are: TSO consumption, household customers, other residential buildings, public institutions, medical centres, consumers where the restriction could cause health or environmental risk, district heating power plants, etc.

The other consumers can have their gas supplies curtailed, and are divided into eight specific "limitation" categories. These categories are prioritised, depending on the size and nature of the consumption sectors.

Additional demand restraint measures are also at the government's disposal in a crisis. Among them are: reducing the opening hours and heating temperature of public buildings; appointing free public holidays; and removing the excise tax on imported fuel oils to incentivise fuel switching from natural gas.

The Hungarian Electricity Law (Act No. LXXXVI/2007) obliges power plants with over 50 MW of output to hold so-called normative and emergency oil stocks, both of which must correspond to a minimum of eight days of average fuel consumption. Some 34 kb/d of gas could be switched to oil in the event of a crisis.

The TSO has indicated that the total volume of fuel saved by interruptible contracts could amount to between 5 and 6 mcm/d. However, the TSO has also indicated that it only knows the interruptible capacities and that the interruptible volumes are known and handled by the traders.

For gas, the "normal" natural gas production level stands at around 7.5-8 mcm/day. In the event of an emergency, production can be increased by 0.5 mcm/day over a maximum period of two to three months.

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Ireland

Key data

Table 4.13.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Demand (kb/d)	92.1	170.0	191.9	161.4	143.2	133.2	132.2
Motor gasoline	20.5	34.5	39.6	34.3	30.6	27.8	-
Gas/diesel oil	34.5	64.0	75.3	69.1	64.4	64.0	-
Residual fuel oil	16.9	31.7	23.0	7.1	5.5	4.1	-
Others	20.2	39.8	53.9	51.0	42.6	37.3	-
Net imports (kb/d)	92.1	170.0	191.9	161.4	143.2	133.2	132.2
Import dependency (%)	100	100	100	100	100	100	100
Refining capacity (kb/d)	56.0	71.3	71.0	72.4	72.4	72.4	-
Oil in TPES (%)**	45	54	54	48	47	43	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.13.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	2 318	1 186	572	285	208	223	1 538
Demand (mcm/y)	2 317	4 013	4 117	5 503	4 836	4 735	4 519
Transformation	1 041	2 132	2 354	3 531	2 926	0	-
Industry	974	995	625	545	731	0	-
Residential	145	511	699	829	667	0	-
Others	157	375	439	598	512	0	-
Net imports (mcm/y)	- 1	2 827	3 545	5 218	4 628	4 512	2 981
Import dependency (%)	0	70.4	86.1	93.0	92.8	95.3	66
Natural gas in TPES (%)	19	25	24	33	31	30	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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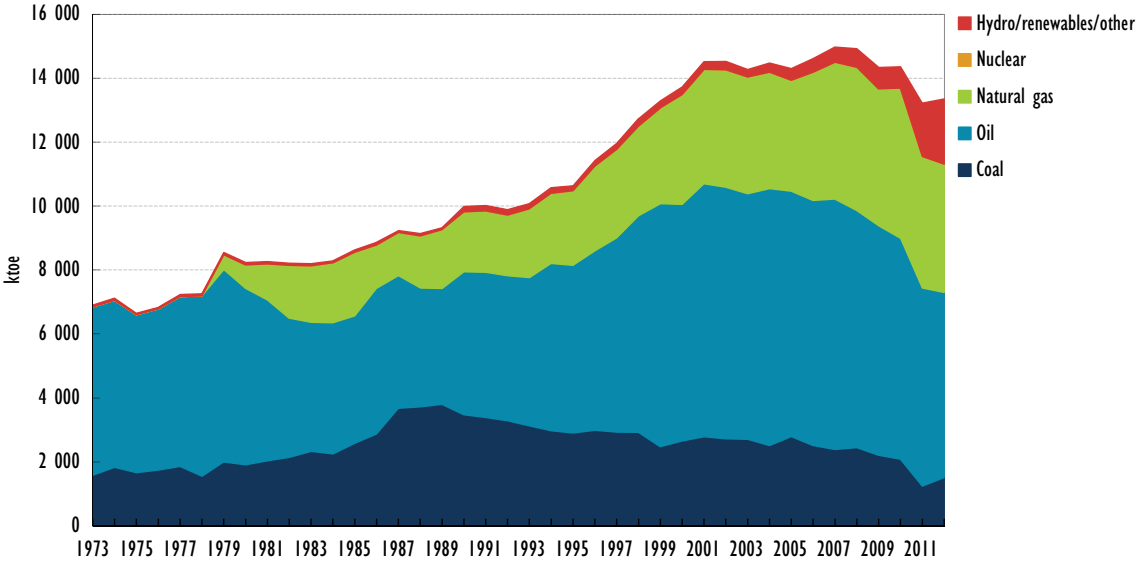
Figure 4.13.1 Total primary energy source (TPES) trend, 1973-2012



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Map 4.13.1 Oil infrastructure of Ireland

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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Map 4.13.2 Gas infrastructure of Ireland

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Country overview

Oil remains the dominant energy source in Ireland, representing 43% of the country's total primary energy supply (TPES) in 2012. Natural gas has taken a growing share of the energy mix – from 19% in 1990 to 30% in 2012. Irish oil demand peaked at 202 thousand barrels per day (kb/d) in 2006, and since then it decreased to 133 kb/d in 2012. With no indigenous oil production, all crude oil is imported. In 2012, roughly 80% of crude oil was supplied from Africa, the remaining 20% came from Norway, while more than 93% of refined products were imported from the United Kingdom.

Ireland meets its stockholding obligation to the International Energy Agency (IEA) and the European Union through a combination of stocks owned by the National Oil Reserves Agency (NORA) and stored in Ireland and in other EU member states, stocks held by NORA under short-term commercial contracts ("stock tickets") in Ireland or other EU member states, and operational stocks held in Ireland by industry (in the case of the EU stockholding obligation, only stocks held by oil consumers that maintain more than 55 days of their previous year's consumption in oil stocks are counted). Ireland has been pursuing a policy of rebalancing its emergency oil reserves by maximising NORA's stocks held in Ireland, and NORA has been making efforts to achieve 88 days of physical stocks, in line with the new obligation set for NORA by the Minister for Energy in April 2013. NORA has also been progressively reducing the use of stock tickets with none being held as of September 2013 and all strategic stock being held as physical stock, either on the island of Ireland (71%) or abroad (29%.)

The use of stocks held by NORA is central to Ireland's emergency response policy, which would be complemented by demand restraint measures if a supply disruption were to become protracted. In the event of a major domestic supply disruption, NORA stocks would be offered for sale to oil import companies on the basis of the proportion of the NORA levy which each company has paid. These companies would then sell the products through their distribution chains into the market in the usual way. In the event of a global supply disruption which would require a collective action by the IEA, NORA stocks would be made available to the market by tender or use of ticketed stocks held abroad. The Oil Security Division of the Department of Communications, Energy and Natural Resources serves as Ireland's national emergency strategy organisation (NESO).

Largely driven by increased demand for electricity and construction of new gas-fired power stations, the demand for natural gas had steadily increased, reaching 5.5 billion cubic metres (bcm) in 2010, but has declined since reaching 4.7 bcm in 2012. The United Kingdom is the single source of natural gas imports for Ireland. In 2012, Ireland imported approximately 4.4 bcm (11 million cubic metres per day) of natural gas from the United Kingdom via two sub-sea interconnectors, which covered up to 92% of the total demand.

Diversification of supply, the encouragement of the development of commercial gas storage, the enhancement of emergency planning and response with partners in the United Kingdom and Northern Ireland, and the development of Common Arrangements for Gas (CAG) with Northern Ireland have all been central to Ireland's overall policy on natural gas security.

With regard to fuel switching, gas-fired power generators in Ireland are required to maintain some fuel-switching capacity. Base-load gas-fired generators are required to hold five days of secondary fuel stocks on site and to be able to run at 90% output capacity for that period in a natural gas emergency, whilstwhilst mid-merit generating units are required to have three days of secondary fuel stocks on site and also to maintain a 90% output.

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Oil

Market features and key issues

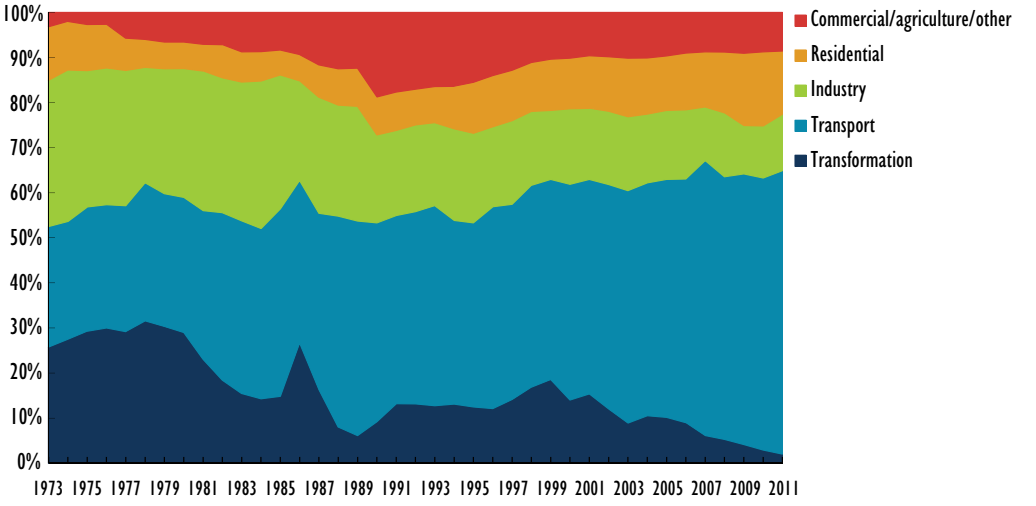
Domestic oil production

There is no indigenous oil production in Ireland; all crude oil is imported.

Oil demand

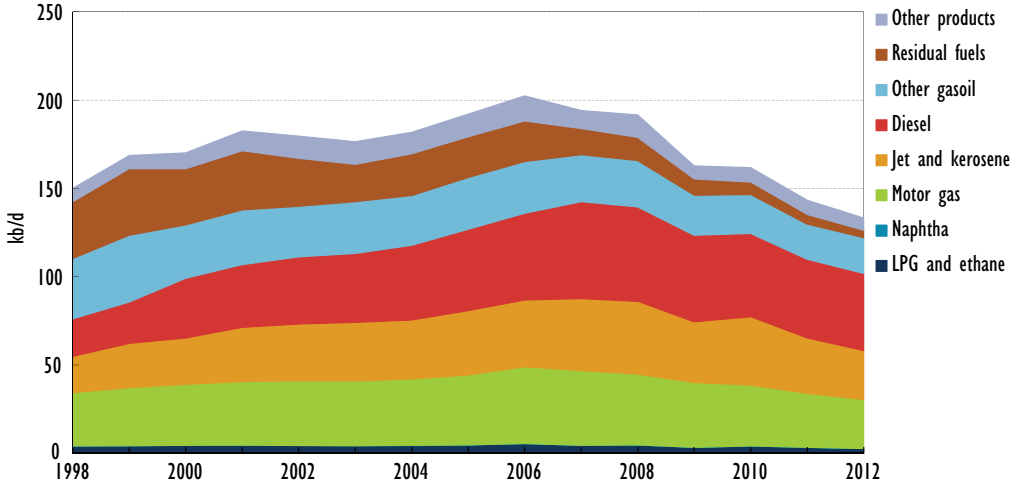
Irish oil demand peaked at 203 kb/d in 2006, and since then it has gradually decreased to 133 kb/d in 2012.

Figure 4.13.2 Oil consumption by sector, 1973-2011



Oil demand in the transport sector has increased from 3.9 million tonnes (Mt) in 2000 to around 4.2 Mt in 2011. The ratio of the transportation sector in the Irish total inland oil demand also increased, from 48% in 2000 to 63% in 2011. In terms of oil demand by product, demand for diesel grew by almost 30% in the period between 2000 and 2012.

Figure 4.13.3 Oil demand by product, 1998-2012



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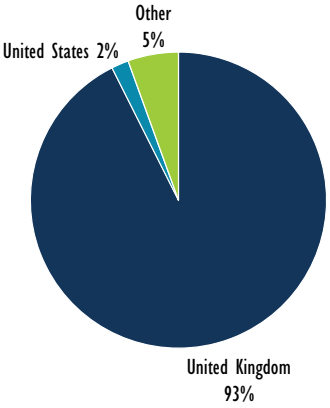
Imports/exports and import dependency

Ireland's oil imports in 2012 were 168 kb/d, consisting of 59 kb/d of crude oil and 107 kb/d of refined products. In 2012, roughly 20% of crude oil was supplied from Norway, while the rest was mainly from Algeria and Nigeria. In the same year, Ireland imported more than 90% of its refined products from the United Kingdom. Conversely, in 2012 Ireland exported 34 kb/d of oil products (mainly fuel oil to the United Kingdom). Therefore, the country's total net oil imports in 2012 were 134 kb/d.

Figure 4.13.4 Oil products imports by origin, 1973-2012



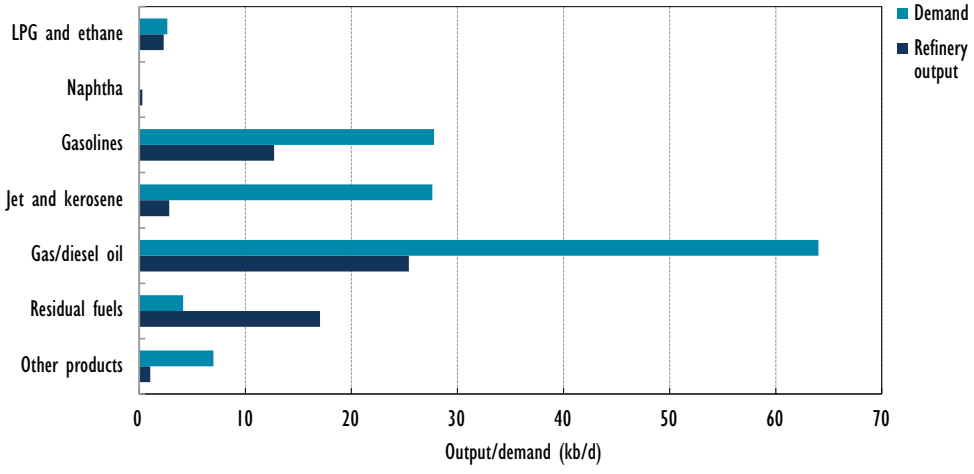
Oil supply infrastructure

Refining

The only oil refinery in Ireland is operated by Phillips 66 at Whitegate in County Cork. It has a distillation capacity of 75 kb/d. Its parallel company, ConocoPhillips, has a stream of planned investments for improving capacity, reliability and capability over the period up to 2014. In 2013, the refinery marketing activities and Bantry storage were put on the market for sale by Phillips 66. The sale process is ongoing and in the meantime Phillips 66 is committed to operating the refinery on a business-as-usual basis.

In 2012, the Whitegate refinery processed roughly 56 kb/d of crude oil; the overall capacity utilisation rate was nearly 85%. In the same year, gas/diesel oil, gasoline and heavy fuel oil accounted for 41%, 21% and 28%, respectively, of the refinery's total product yield.

Figure 4.13.5 Refining output vs. demand, 2012



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Under the agreement of sale of the refinery by the state in 2001 with the private-sector owners, the refinery must remain operational until at least 2016. This is a requirement for Phillips 66 and any subsequent owners.

In July 2013, the Department of Communications, Energy and Natural Resources published a report entitled *Study of the Strategic Case for Oil Refining Requirements on the Island of Ireland*. The government's primary conclusion was that the presence of an operational refinery on the island of Ireland provides flexibility, enhancing the options available to the state in the event of an oil supply disruption by providing an alternative source of product and thus mitigating a complete reliance on product imports. It concludes that the continued operation of the Whitegate refinery on a commercial basis is highly desirable.

An additional finding of the study was that existing oil import facilities on the island of Ireland taken as a whole offer a robust infrastructure that would provide comfortable alternatives in the event of a serious disruption at any of the six principal oil ports. The study demonstrates that the improved motorway network and the robust capacity at Irish ports have enhanced oil security in recent years. Ireland will seek to deepen co-operation with counterparts in Northern Ireland to ensure the robustness of oil supply infrastructure on the island as a whole.

Ports and pipelines

All oil requirements are fulfilled by seaborne imports. The six ports in Ireland with oil terminals can accept imported refined products for commercial distribution: Dublin, New Ross, Whitegate, Cork (Marina), Foynes and Galway. Dublin Port is the largest and can handle larger cargoes than many other ports, receiving 45% of the transport and heating fuels used in Ireland.

There is no oil pipeline infrastructure in Ireland. Domestic distribution is mainly by road. Ireland also has no cross-border pipelines for transportation of crude oil or oil products.

Storage capacity

Ireland's main storage facilities are located at the Whiddy Island oil terminal (Bantry, County Cork), the Whitegate oil refinery (County Cork), Tarbert, Dublin and Kilroot (County Antrim) and oil company depots in Dublin Port, Cork, New Ross, Foynes and Galway.

A significant proportion of Ireland's storage capacity is at Bantry on Whiddy Island, with a total capacity of 1 030 kilotonnes (some 7.6 million barrels), which can be used for all three categories of main products and crude storage. About half of the facilities on Whiddy Island are rented out and used by the Irish stockholding agency, NORA. Roughly 51% of the agency stocks in Ireland are stored on this island. In the event of a supply disruption, NORA stocks on Whiddy would first have to be loaded onto vessels and shipped to one of the oil ports in Ireland.

Decision-making structure

The Minister for Communications, Energy and Natural Resources (DCENR) is responsible for Ireland's emergency response preparedness. Its Oil Security Division serves as Ireland's NESO with the assistant secretary of the department serving as its head. In emergency situations, the division works in close co-operation with NORA and the oil industry and with the Irish Office of Emergency Planning, which plays an overall co-ordinating role during emergencies of all types.

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Under the Fuels Acts of 1971 and 1982, the minister is empowered to regulate the acquisition, supply, distribution or marketing of fuels, including petroleum products – if the government decides that an emergency situation warrants such action. Under the National Oil Reserves Agency Act 2007, the drawdown of NORA stocks may be authorised by way of a ministerial decision and written instruction to NORA.

Stocks

Stockholding structure

Ireland meets its stockholding obligation to the IEA and the European Union primarily with stocks owned by NORA and stored in Ireland and in other EU member states with which Ireland has concluded an oil stockholding agreement.

Under the National Oil Reserves Agency Act 2007, NORA is responsible for ensuring that sufficient stocks are available to meet Ireland's stockholding obligations. The oil industry and large consumers also hold operational stocks in Ireland. Oil consumers that hold 55 days of their previous year's oil consumption in oil stocks may apply for an exemption from the NORA levy. These consumers' stock also counts towards Ireland's IEA and EU stockholding obligations. In addition, NORA has the option to obtain stocks under short-term commercial contracts ("stock tickets") in Ireland or other EU member states with which Ireland has concluded a bilateral oil stockholding agreement or memorandum of understanding (MoU), with an option to purchase the oil in emergency circumstances during the period of the contract. As a result of stock rebalancing in 2013, no such stock tickets are held and all Ireland's strategic oil stocks are held as physical stock.

Crude or products

At the end of 2012, roughly 76% of the domestically held NORA stocks were middle distillates, while the remainder was motor gasoline.

Location and availability

Stocks held abroad consist of stocks wholly owned by NORA. Ireland has bilateral agreements with the Netherlands, Sweden and Spain and MoUs with Denmark and the United Kingdom.

At the end of September 2013 NORA held 71% of total stocks in Ireland as physical stocks and 29% as physical stocks abroad with no stock tickets.

Monitoring and non-compliance

The Minister for Communications, Energy and Natural Resources receives detailed monthly statistical returns from oil companies. Individual company data is cross-checked against returns by other companies.

The department also carries out regular audits to ensure the accuracy of statistical reporting.

Stock drawdown and timeframe

The use of stocks held by the stockholding agency NORA would be complemented by demand restraint measures if either an international or domestic supply disruption were to become protracted. The Minister for Communications, Energy and Natural Resources has the authority to authorise the release of NORA's stocks in response to supply disruptions. After consultation with NORA, the minister may issue a written

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direction specifying the procedures to be applied by NORA for releasing such oil stocks, and authorising NORA to release oil stocks in accordance with those procedures.

Decisions for drawdown/release of NORA stocks would be made within a time frame of 24 to 48 hours. In the event of a major domestic supply disruption, NORA stocks would be sold by NORA to oil companies that pay the NORA levy, on the basis of the proportion of the levy that they pay. The oil companies would then sell the oil products through their distribution channels to the market in the usual way.

In the event of a global supply disruption requiring an IEA collective action, NORA stocks would be made available to the market by tender. In such an event, the assistant secretary for energy of the department would take a decision to draw down NORA stocks within 48 hours, from the moment of the notice of activation under the Initial Contingency Response Plan (ICRP) of the IEA. Then the department would obtain the relevant approval from the minister. A tender process for release of NORA stocks, if such option is pursued, is estimated to take from one to two weeks from the time of placing the tender.

Financing and fees

NORA receives no funding from the government. The operational costs of NORA are financed by a levy, which is currently EUR 0.02 (two cents) per litre on sales of gasoline, kerosene, gas oil, diesel oil and fuel oils. Under the NORA Act, aviation fuels and marine bunkers are exempt from the NORA levy. The NORA levy is paid by oil companies on their disposal of oil products.

According to NORA's 2012 financial statement, its operating costs in that year were EUR 35.7 million, comprised of EUR 31.6 million of storage costs and EUR 4.1 million of operating costs.

Other measures

Demand restraint

It is envisaged that demand restraint measures would be introduced incrementally because Ireland would be seeking to minimise the impact of major oil supply shortages initially through the drawdown of emergency oil stocks held by NORA.

Under the Fuels (Control of Supplies) Acts 1971 and 1982, the government may make an order authorising the Minister of Communications, Energy and Natural Resources to intervene whenever the government is of the opinion that the "exigencies of the common good" necessitate the regulation or control of the acquisition, supply, distribution or marketing of fuels held by the oil industry. Once the government order is in place, the minister is empowered to make an order or orders in respect of regulation of a certain fuel or fuels. It is estimated that it would take approximately 24 hours from the point of making the necessary ministerial order or orders to implement demand restraint measures.

Details of Ireland's demand restraint measures are set out in the department's *Handbook on Oil Supply Disruptions*. There are various indicative demand restraint measures:

- national speed limits to be reduced and enforced by *An Garda Síochana* (police)
- traffic restrictions in urban areas where adequate public transport exists
- alternate driving days for private motor vehicles, implementation by *An Garda Síochana*
- restrictions to petrol stations on the basis of general supply availability reduction levels
- imposition of minimum and maximum sale amounts

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- common opening hours, restricted opening hours for fuel sales
- designated pump islands at larger petrol stations for sole use of authorised emergency services and priority services and users only, priority services and users will have preferential access at all other outlets
- restrictions on deliveries to business/home-based tanks to follow general supply availability reduction levels.

Fuel switching

Ireland's fuel-switching capacity out of oil has decreased to a negligible level, as the country's reliance on oil for electricity generation (1.2% in 2012), especially on heavy fuel oil (0.9% in 2012), has fallen in recent years because of the increased use of gas. This trend is expected to continue and the use of oil in power generation will dwindle further in the near future.

Other

Given that Ireland has no indigenous oil production, surge production of oil is not considered an emergency response measure in the country.

Gas

Market features and key issues

Gas production and reserves

Indigenous gas production commenced in 1978 at the Kinsale Head gas field in the Celtic Sea, and brought ashore at the Inch entry point in County Cork. The Kinsale Head gas field was subsequently supplemented with production of gas from two satellite fields, the Ballycotton and South West Lobe (SWL) gas fields. The SWL gas field has since been depleted, and now operates as a seasonal gas storage facility. In 2003, the adjacent Seven Heads gas field was tied into the offshore Kinsale infrastructure, and Seven Heads gas was brought ashore at Inch. Production of gas from the Kinsale and Seven Heads gas field is now in decline, and is small relative to total demand; it is being superseded by the gas storage operation. In total, the Inch entry point provided 6% of Ireland's annual gas supplies and 10% of peak day gas supplies in 2012-13.

It is anticipated that the main source of future indigenous Irish gas production (in the short term) will be in the Corrib gas field. The gas field is currently being developed and is expected to start commercial production in 2015. Gas production from the field is expected to meet about 42% of annual demands over the first two years of operation. However, Corrib has a short production profile and is expected to decline within six years of its commencement. Ireland, therefore, is likely to remain dependent on gas imports from the United Kingdom in the medium term.

Gas demand

Ireland's current annual gas demand which stood at 4.7 bcm in 2012 (and peak day gas demand) has decreased from its peak in 2009-10 when it reached about 5.5 bcm. The decline in demand can be attributed to a downturn in Ireland's economy, and the increased generation of renewable electricity.

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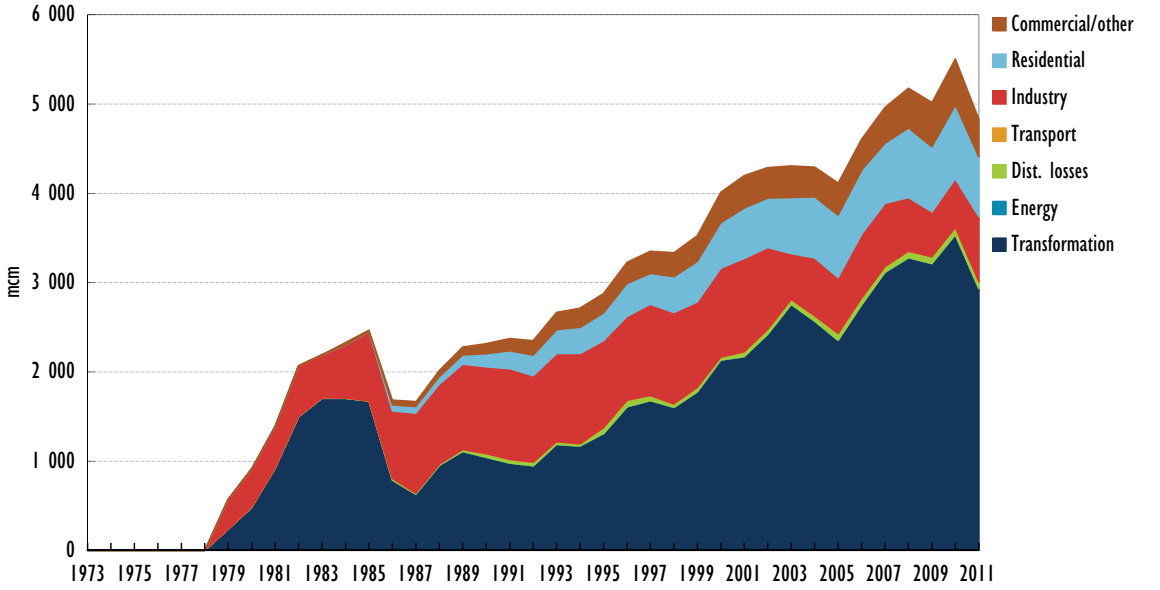
Figure 4.13.6 Natural gas consumption by sector, 1973-2011



According to gas consumption data for 2012-13, the electricity power generation sector accounted for 56% of annual gas demand, while the industrial and commercial sector and the residential sector accounted for 28% and 17% respectively.

In relation to peak day gas demand, the electricity power generation sector accounted for 56% of peak gas demand, the industrial/commercial sector for 23% and the residential sector for 21%.

Gas import dependency

The United Kingdom is the only source of natural gas imports into Ireland. In 2012, Ireland imported 4.5 bcm of natural gas from the United Kingdom, through two sub-sea interconnectors, which supplied approximately 94% of Ireland's total annual gas demand. Following the depletion of the Corrib gas field, the majority of Ireland's demand will continue to be met from UK imports through the Moffat entry point. However, this scenario could potentially change if the Shannon liquefied natural gas (LNG) terminal proceeds. A commercial decision is yet to be made regarding the project, which is otherwise well advanced.

Gas supply infrastructure

Pipelines

There are two entry points for natural gas for Ireland: Inch entry point in County Cork and Moffat entry point in western Scotland. The Inch entry point connects the Kinsale Head and Seven Heads offshore gas fields and the Kinsale gas storage to the Irish onshore network. There is a compressor station in Midleton near Cork, which compresses the gas to flow north towards Dublin.

The Moffat entry point (with a technical capacity of 23.4 mscm/d) connects the UK national transmission system to the Irish high-pressure transmission network, enabling Ireland to import natural gas from the United Kingdom. This interconnector system is made up of two sub-sea pipelines between the north of Dublin and Scotland

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(Interconnector 1 has a capacity of 17 mcm/d and Interconnecter 2 has a capacity of 23 mcm/d). There are also two compressor stations at Beattock and Brighouse Bay in Scotland, and the 110 km onshore pipeline between Brighouse and Moffat.

The actual combined capacity of the sub-sea interconnectors is 40 bcm but is limited to less than 23 mcm/d because of limited capacity at Brighouse Bay. There is a sub-sea spur connection to the Isle of Man from Interconnector 2. An off-take station at Twynholm in Scotland, located en route to the Brighouse Bay compressor station, supplies gas from the United Kingdom to Northern Ireland through the Scotland-Northern Ireland Pipeline (SNIP).

The onshore transmission system of Ireland is made up of a ring-main system between Dublin, Galway and Limerick, with cross-country pipelines connecting the ring-main system to Cork, Waterford, Dundalk and the Corrib Bellanaboy terminal in Mayo. In order for the Irish gas network to accommodate increasing Irish gas demand, substantial investments have been made in recent years.

Storage

Ireland has one gas storage facility off the southwest coast at Kinsale, which is operated on a commercial basis. This facility has the capacity (depending on the levels of gas held in storage at any given time) to supply 48% of protected customers for up to 50 days, which equates to 10% of annual demand. The Kinsale facility currently has a working volume of around 218 mcm, which is equivalent to approximately 5% of Ireland's annual gas consumption in 2012. It has a maximum withdrawal rate of 2.5 mcm/d and a maximum injection rate of 1.6 mcm/d. Gas imports from the United Kingdom are used to refill the storage facility at Kinsale in addition to site production. The operator of the facility is currently examining the feasibility of developing additional storage at the site.

Emergency policy

Diversifying supply, encouraging the development of commercial gas and LNG storage, enhancing emergency planning and response with partners in the United Kingdom and notably Northern Ireland constitute the central parts of Ireland's policy on natural gas security.

The Commission for Energy Regulation (CER) has statutory responsibility for monitoring and ensuring security of natural gas supply in Ireland. Under the powers derived from Statutory Instrument 697/2007 the CER is authorised to appoint the national gas emergency manager (NGEM) and approve the natural gas emergency plan (NGEP). Gasink, the transmission system operator, has been appointed as the NGEM and is responsible for declaring a gas emergency and activating and implementing the provisions of the NGEP.

Statutory Instrument 336/2013 set out the functions of the CER as the competent authority for the purposes of EU Regulation 994/2010. The functions of the competent authority include, among others, the appointment of authorised officers to assist in the response to and management of a gas supply emergency.

The NGEP was developed following extensive consultation with relevant stakeholders and is tested on an annual basis with Great Britain and Northern Ireland. In the event that a natural gas emergency is declared by the NGEM, the NGEM will then activate the NGEP. Action taken involves the NGEM convening the gas emergencies response team (GERT), which will be responsible for implementing the directions of the NGEM as part of the operational response. The GERT is comprised of representatives from

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Bord Gáis Éireann (BGE), Eirgrid (the electricity TSO in Ireland), ESBNetworks (ESBN), the CER, the Department of Communications, Energy and Natural Resources (DCENR) and Gasink. With the assistance of the GERT the NGEM will make ongoing assessments of the emergency and advise on action to be taken to respond to the crisis.

Actions to be taken as a first step to curtail gas supplies during an emergency include the NGEM instructing gas-powered electricity generators to switch to alternative fuel within five hours of the emergency being declared.

In the event of an escalation of the crisis or the NGEM assessing the balance between supply and demand to be inadequate, NGEM will instruct large industrial users to cease using gas. This will enable the NGEM to maintain supplies to protected customers for as long as possible. If the crisis escalates further, load shedding for daily metered and non-daily metered users will take place.

Emergency response measures

Market suppliers are not required to hold strategic gas reserves in Ireland. In the event of a gas emergency, the operator of the Kinsale commercial storage facility would be required to release gas from its facility if instructed to do so by the NGEM. The NGEM would also instruct the operator to cease injection of gas into storage.

Fuel switching

The CER Secondary Fuelling Decision of 2009 imposes an obligation on gas-fired generators in Ireland to have the capability to switch to alternative fuel within five hours of an emergency being declared.

Base-load gas-fired generators are required to hold five days of secondary fuel stocks on site and must be able to run at 90% output capacity for that period during a gas emergency.

Mid-merit generating units are required to hold three days of secondary fuel stocks on site and also to maintain a 90% output capacity for that period.

If gas-powered generators are unable to hold fuel stocks on site, they must ensure that fuel stocks are located in close proximity to the plant with a dedicated fuel line and pumping facilities.

Demand restraint

Large industrial customers would be the first to have their supplies curtailed, following the power generation sector. The NGEM would instruct large users to reduce consumption or shed load in order to maintain supplies to protected customers for as long as possible. The CER has the legal powers to enforce load shedding, while Eirgrid, the electricity TSO, is responsible for implementing the load shedding plan. ESBNetwork's role in this process is crucial and has been tested on an ongoing basis with Eirgrid and annually with the United Kingdom and Northern Ireland.

Regional arrangements are also in place to respond to a gas supply emergency. In the case of a gas supply disruption originating in the United Kingdom, Ireland, Northern Ireland and the United Kingdom will apply load shedding on a pro-rata basis. Households in each jurisdiction share equal priority and gas supply will continue from Moffat until supplies to households in the United Kingdom cannot be maintained. Significant progress has been made between relevant parties in developing load-shedding protocols between Ireland and Northern Ireland and Ireland (all island) and the United Kingdom.

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Italy

Key data

Table 4.14.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	90.3	78.0	124.5	107.6	103.4	104.6	135.6
Demand (kb/d)	1 868.4	1 853.8	1 780.6	1 544.2	1 493.8	1 352.8	1 112.9
Motor gasoline	301.8	397.9	326.8	239.4	244.1	215.4	-
Gas/diesel oil	566.0	561.8	649.3	614.5	608.9	550.8	-
Residual fuel oil	551.4	455.8	276.1	144.0	115.9	102.8	-
Others	449.3	438.3	528.4	546.4	524.9	483.7	-
Net imports (kb/d)	1 778.1	1 775.8	1 656.1	1 436.6	1 390.4	1 248.2	977.3
Import dependency (%)	95.2	95.8	93.0	93.0	93.1	92.3	88
Refining capacity (kb/d)	2 804.0	2 340.6	2 320.9	2 403.2	2 403.2	2 403.2	-
Oil in TPES (%)**	58	52	45	39	37	35	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.14.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	17 296	16 633	12 071	8 406	8 449	8 605	7 391
Demand (mcm/y)	47 405	70 745	86 265	83 097	77 917	74 915	76 344
Transformation	10 033	22 819	34 532	34 009	32 163	0	-
Industry	17 778	21 492	18 138	13 330	11 886	0	-
Residential	13 731	18 280	22 890	22 830	21 965	0	-
Others	5 863	8 154	10 705	12 928	11 903	0	-
Net imports (mcm/y)	30 109	54 112	74 194	74 691	69 468	66 310	68 953
Import dependency (%)	63.5	76.5	86.0	89.9	89.2	88.5	90
Natural gas in TPES (%)	27	35	39	41	38	39	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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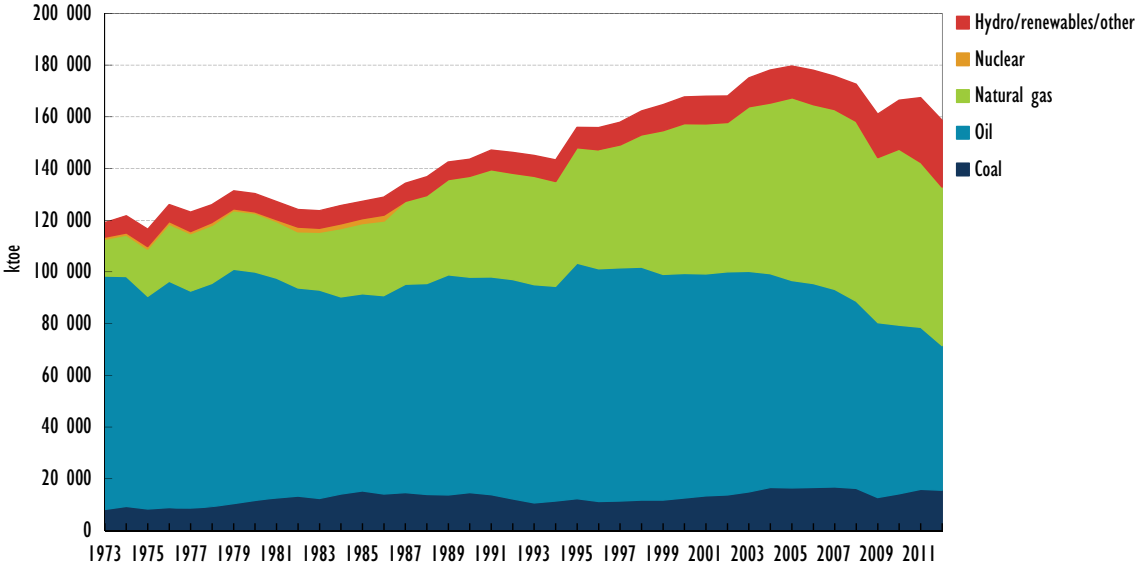
Figure 4.14.1 Total primary energy source (TPES) trend, 1973-2012



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Map 4.14.1 Oil infrastructure of Italy

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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Map 4.14.2 Gas infrastructure of Italy

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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Country overview

Italy has some indigenous production of oil and natural gas, but both oil and gas production will progressively decline in the coming years. In 2012, Italy's total domestic oil production met only 7.7% of its domestic demand.

Italy is among Europe's largest energy consumers, with its total primary energy supply (TPES) standing at around 159 million tonnes of oil-equivalent (Mtoe) in 2012. The supply mix remains dominated by oil and natural gas, which – although now declining – together have accounted for well over 70% of Italy's TPES since 1973.

Italian oil demand is increasingly concentrated in the transportation sector. The progressive dieselisation of the vehicle fleet has significantly altered the demand structure. Diesel increased from 18% of total oil consumption in 1998 to 33% in 2012, while the share of gasoline declined from 23% to 16% during the same period.

The shift away from oil to natural gas, reducing oil's share from over 76% in 1973 to 36% of the TPES in 2012, is mainly owing to the increased use of natural gas in power generation. Natural gas-fired electricity plants have replaced dual-fired electricity plants. The old oil-fired plants are used only to guarantee the fuel-switching mechanism during a possible gas system crisis. The shift away from dual-fired electricity plants to natural gas-fired electricity plants renders an emergency response system for natural gas indispensable. To address this need, an emergency plan is being implemented, together with the other EU member states. Italy fulfils its minimum oil stockholding requirements to the International Energy Agency (IEA) by placing stockholding obligations on industry. Companies are obliged to report to the Ministry of Economic Development on a daily basis, stating the exact location, product type and quantity of their stocks. A company's non-compliance with its obligations can result in substantial financial penalties. In an emergency, oil operators can be granted permission to draw on stocks.

Italy has also established a natural gas emergency response policy which provides for mandatory security of supply measures such as minimum requirements for strategic and working gas storage. The level of strategic storage should be sufficient to replace the equivalent of 50% of peak imports at the main national entry point for 60 days. Italy's maximum withdrawal capacity from storage could theoretically cover almost 70% of peak winter demand.

Oil

Market features and key issues

Domestic oil production

Domestic production of crude oil and other hydrocarbons has declined overall between 2005 and 2012 – from 124.5 thousand barrels per day (kb/d) in 2005 to 104.6 kb/d in 2012. However, there was a slight 1.2 kb/d increase in oil production from 2011 to 2012, with the level of production projected to continue to increase – reaching 135.6 kb/d by 2018. Italy's total domestic oil production only met 7.7% of domestic demand in 2012 – a level that is expected to improve marginally, meeting 12% of domestic demand by 2018.

Oil demand

Italian oil demand is continuing to trend downwards, with a decline of more than 24% between 2005 and 2012. Forecasts indicate that this trend is set to continue, with

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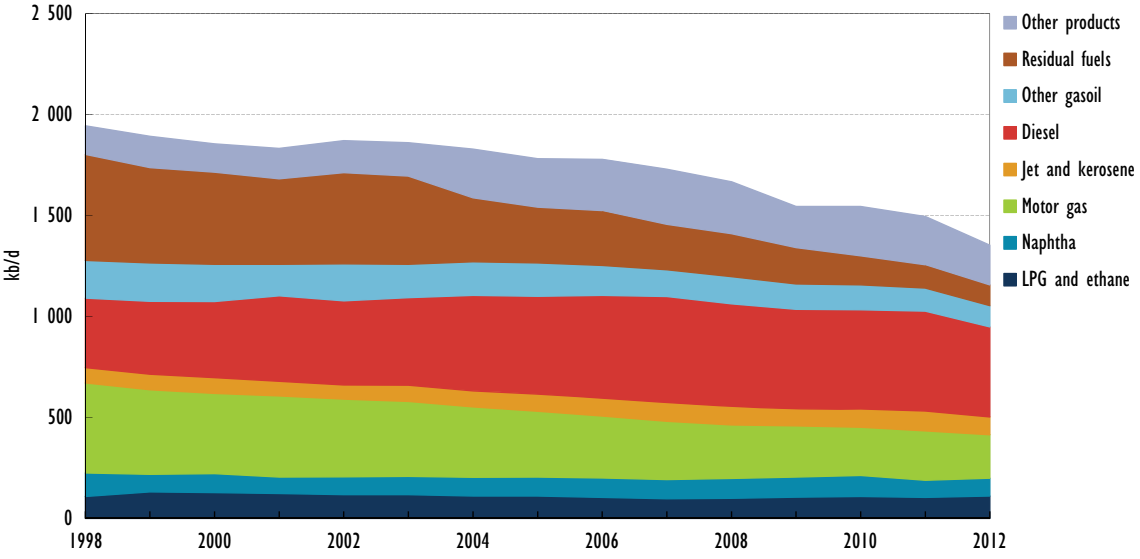
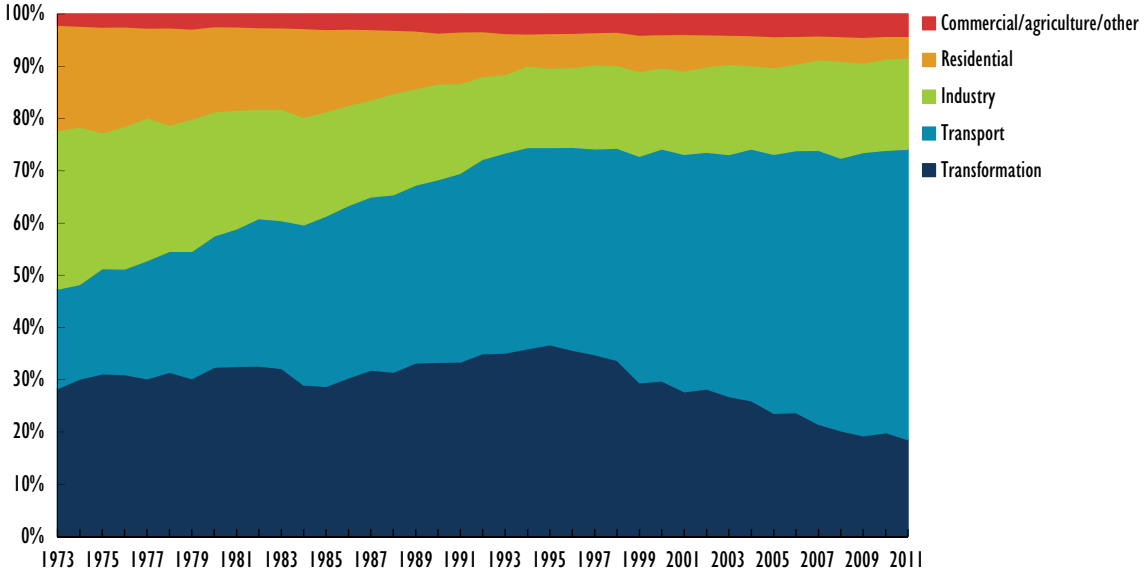
demand expected to decline by a further 17.7% by 2018. As natural gas and renewables have gradually replaced oil in the electricity generation and other sectors, the use of oil is becoming increasingly concentrated in the transportation sector.

Figure 4.14.2 Oil consumption by product, 1998-2012



With regard to the transport sector, oil consumption increased significantly in the period from 1998 to 2012, but the progressive dieselisation of the vehicle fleet has significantly altered the demand structure. Diesel increased from 18% of total oil consumption in 1998 to 33% in 2012, while the share of gasoline declined from 23% to 16% during the same period.

Figure 4.14.3 Oil demand by sector, 1973-2011



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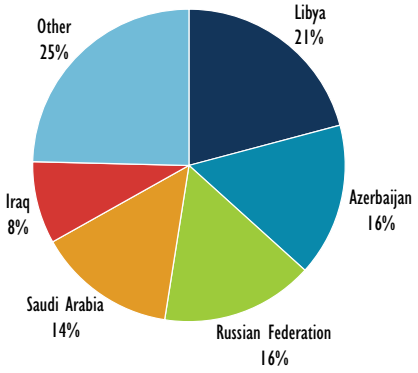
Imports/exports and import dependency

Italy is highly dependent on imports for its oil supply, importing 92.3% of the country's requirements in 2012. The country's import sources are widely diversified, however, with the Russian Federation, Libya and Saudi Arabia as the dominant sources of oil, each accounting for around one-fifth of all Italian crude oil imports. Azerbaijan and Kazakhstan together represent an additional quarter of Italian crude oil imports.

Figure 4.14.4 Crude oil imports by origin, 2012



Oil company operations

The Italian oil market is fully open, with decisions regarding imports, exports, trade and pricing determined by the industry participants. The government intervenes only to protect competition and avoid abuse of dominant market positions. Companies proposing to set up refineries and oil product storage facilities require authorisation from the Ministry of Economic Development.

The former state oil company Eni has a dominant position in the Italian upstream oil and gas sector, although a number of private-sector Italian and foreign companies have also established a significant presence.

With regard to the downstream sector, distribution is principally undertaken by integrated oil companies. Eni has the largest retail market share in Italy, with a 31.2% market share in 2012 (up 0.7% from 2011). The company operates 4 780 service stations in Italy, under the Eni and Agip brands. In addition, independent pumps and supermarket pumps collectively account for around half of the country's retail market.

Oil supply infrastructure

Refining

Italy plays an important role as Europe's largest exporter of refined products, providing finished products (gasoline, diesel and residual fuels) to other countries.

There are 14 major refineries operating in Italy, 11 of which are located along the coast and are supplied by sea. The other four are situated in the Po Valley, in the north of Italy, and are supplied by pipelines from Genoa, Venice and Vado Ligure. In 2012, total refining output stood at around 1.7 mb/d – down from 2.1 mb/d in 2008.

The continuing decline in domestic demand for oil products (down 7 Mt in 2012) has led to a decrease in the refining volumes of both crude oil and semi-finished products to one of the lowest levels in the last two decades. The average utilisation rate of domestic Italian refineries declined to 78% in 2012.

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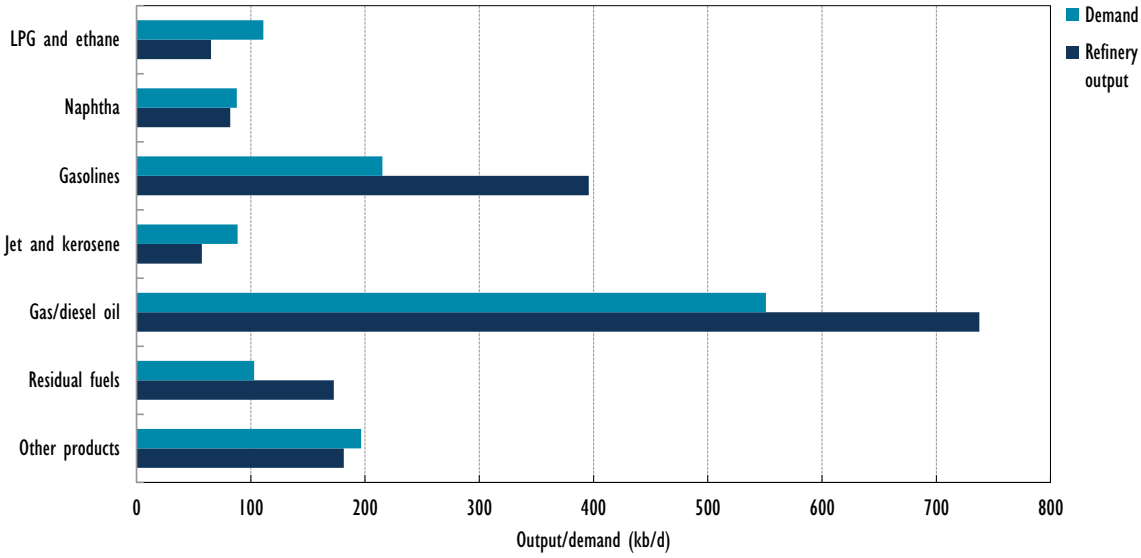
Figure 4.14.5 Refinery output vs. demand, 2012



Substantial investments have been carried out in recent years in order to adapt Italian refineries to changes in the oil market – a declining share of heavy fuel oil in the power sector and a growing share of cleaner fuels in the transport sector. As a net exporter, Italian refineries produce a surplus of gasoline, diesel oil and residual fuels, but have a deficit of jet and kerosene, liquefied petroleum gas (LPG) and ethane and naphtha.

Ports and pipelines

Italy has 16 crude oil tanker ports, four of which (at Taranto, Milazzo, Falconara [Ancona] and Augusta [Santa Panagia] can receive cargo ships of up to 300 000 dead weight tonnes. As most refineries are located along the Mediterranean coast, there are relatively few crude oil pipelines in Italy.

There are two major crude oil pipelines: the Central European Line (CEL) from Genoa (1 mb/d capacity), which supplies inland refineries in northern Italy and the Swiss refinery of Collombey; and the Trans-Alpine Pipeline (TAL) from Trieste, which supplies Germany, Austria and the Czech Republic. The trunk line, from Trieste to Ingolstadt (TAL-IG), has a capacity of 850 kb/d. However, there is no connection between the eastern and western halves of the northern pipeline network, reducing its potential flexibility during an oil supply disruption.

Storage capacity

Italy has 704 industrial and commercial storage depots across the country, with a total storage capacity of at least 26 million cubic metres (mcm). Of these, over 50% are located in four regions in the north of the country. Storage capacity is roughly split into one-third crude and two-thirds finished products.

Decision-making structure

Responsibilities for energy policy are shared between the central government and regional authorities. The Ministry of Economic Development is responsible for energy policy, and for maintaining an operational handbook on emergency procedures and measures for oil supply disruptions. The latest version of the handbook emphasises the following measures in the event of an oil supply disruption: voluntary demand restraint

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campaigns (public appeals to reduce energy consumption); reduced heating levels and hours; driving restrictions; stock drawdown; and fuel switching away from oil to other sources in electricity generation.

Within the Ministry of Economic Development, the Oil Office of the Security of Supply and Energy Infrastructure Directorate of the Department of Energy functions as the permanent body of the national emergency strategy organisation (NESO). Its role is to monitor the oil market, and in the case of an emergency, to prepare information, data and studies, and to ensure liaison with the IEA and industry. It is also responsible for monitoring industry's compliance with minimum stockholding requirements.

In a disruption, the Ministry of Economic Development would convene the full NESO body, called the Conference of Services. This includes representatives from several relevant ministries: the Ministry of Foreign Affairs, the Ministry of the Interior and its Department for Civil Defence, the Ministry of Transport, the Ministry of Defence, the Ministry of Environment, the Ministry of Health and the Ministry for Communications. The Conference of Services also includes representatives from the oil industry and industry associations and recently from the Central Oil Stocks Entity (OCSIT). The Conference of Services, chaired by a representative of the Ministry of Economic Development, would meet within 24 hours and would decide the measures to be taken in a supply disruption.

Stocks

Stockholding structure

All stocks held in Italy are industry stocks, with oil industry operators subject to a compulsory stockholding obligation. Italian legislation[5], in compliance with EU Council Directive 2009/119/EC of 14 September 2009, requires that total compulsory stocks for the country as a whole must correspond to not less than 90 days of average daily net imports or 61 days of average daily inland consumption, whichever of the two quantities is greater.

The stockholding obligation is distributed proportionally among the various oil companies in the market on the basis of product amounts released for inland consumption in the previous year. There are approximately 100 companies with stockholding obligations in Italy. Individual stockholding commitments of companies may be transferred from one to another through leasing or storage rental agreements.

From 2014, the OCSIT (established in 2013) will progressively assume responsibility for an increasing proportion of the country's stockholding obligation from industry.

Crude or products

Italian law stipulates that 30% of compulsory stocks must consist of products from four key categories (gasoline, diesel, fuel oil and jet fuel). Obligated companies are then free to determine the makeup of the remainder of their obligated stock. Compulsory and commercial stocks can be, and often are, commingled.

Location and availability

For security of supply reasons, Italian law requires that at least 30% of compulsory stocks (the product component consisting of gasoline, diesel, fuel oil or jet fuel) be stored on Italian territory. However, the country has no maximum ceiling for the amount of stock that companies can hold in other EU member states to fulfil the remainder of their stockholding obligation.

5. Decreto legislativo, number: 249; Official Journal: Gazzetta Ufficiale della Repubblica Italiana, number: 22.

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Decree 22/2001 sets out guidelines for intergovernmental agreements on stockholding with other EU member states, in order to facilitate the coverage of stock obligations for companies. Italy has bilateral agreements with Germany, Hungary, Malta, the Netherlands, Slovenia, Spain, Denmark and the United Kingdom. Most stocks held in other countries under bilateral agreements are in the form of tickets. As of April 2013, around 14.75 mb of compulsory stocks were held in other countries, accounting for around 15 days of net imports.

Monitoring and non-compliance

Companies are obliged to report to the Ministry of Economic Development the exact location, quality and quantity of stocks on a daily basis. In collaboration with the Revenue Guard Corps and the Customs Agency, the ministry monitors each company's compliance with the decree obligations.

The standard sanction for breaching stock obligations is a fine of EUR 6.5 per day per tonne by which the company falls short of its prescribed minimum for that specific location.

Stock drawdown and timeframe

In an IEA collective action, the ministry has the authority to require industry to release stocks. The time required from a government decision to release stocks until the commencement of the physical delivery of those stocks is estimated to be less than 24 hours.

A NESO decision to use emergency reserves during a supply disruption would be announced in a ministerial decree that would authorise companies to reduce their mandatory stocks by a certain amount, and to make these stocks available to the market. This decree would include an indication of each company's share of stock drawdown.

Financing and fees

No financial support is given to oil companies for holding stocks.

Other measures

Demand restraint

The Conference of Services (the full NESO body) has the legal authority to decide upon demand restraint measures, implementing them through its operational structures.

The specific measures considered include: appeals to the public for voluntary measures to limit consumption; a reduction in domestic heating; and possible driving restrictions. During a crisis, monitoring activities would be intensified, including increased frequency of reporting of stock levels and product deliveries to the market. Industry participants would also be required to submit forecasts of anticipated sales on a regional basis. The regional prefectures would become responsible for monitoring deliveries to vital sectors and assuring initial data verification of regional reporting. Regional shortages of oil products could be addressed through a redistribution of supplies, subject to approval by the Ministry of Economic Development.

The Italian government has indicated that a driving ban is the measure that would be prioritised if it resorted to demand restraint measures. Italy has significant experience in imposing odd/even licence plate schemes, mainly to reduce air pollution in metropolitan areas during the winter. On an average day of application, this measure can reduce the normal consumption of gasoline and diesel for transportation by 10% to 15%. As the use of oil for heating is diminishing over time, the scope for oil savings through demand restraint measures on domestic heating is declining.

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Fuel switching

Around one-third of oil-fired electricity generation plants can switch to natural gas in the event of an emergency. The potential of this emergency response measure is rapidly declining because of the shrinking share of oil in thermoelectric plants.

Other

The scope for surge production of crude oil is very limited as active fields are operating at, or close to, their maximum capacity.

Gas

Market features and key issues

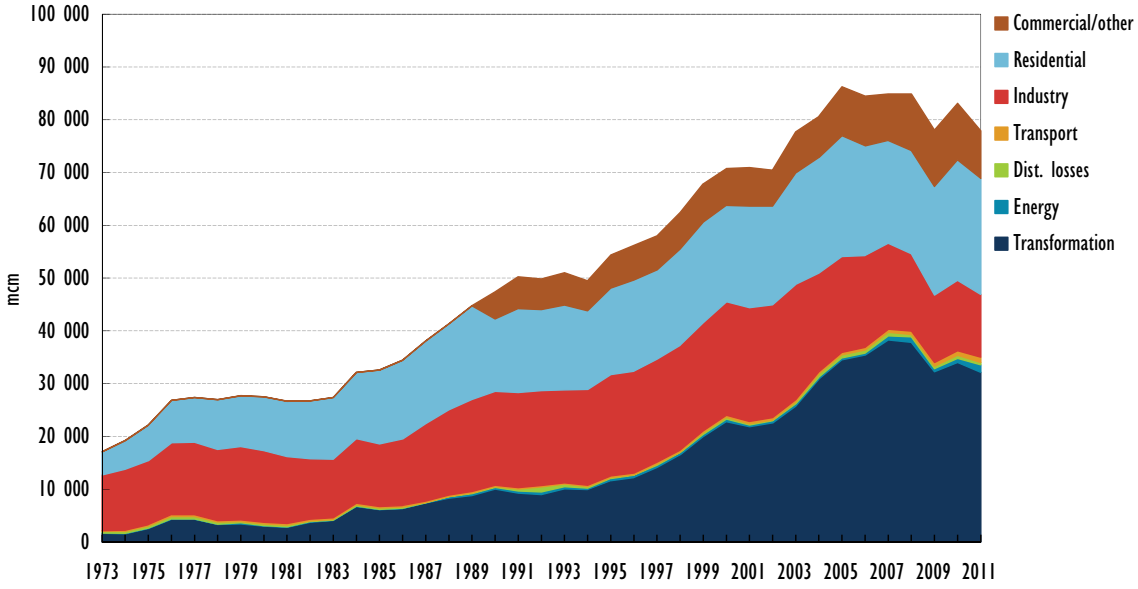
Gas production and reserves

Italy has indigenous production of natural gas. Around two-thirds of Italy's gas reserves are located offshore. Whereas in 1973, domestic production accounted for almost 90% of Italy's supply needs, Italy's production has progressively declined over the last 40 years, from 15.4 billion cubic metres (bcm) in 1973 to 8.6 bcm in 2012 (around 11% of Italy's supply needs).

Gas demand

Demand for natural gas in Italy has grown rapidly over the last decades, notably as part of a national programme to alleviate the country's dependence on oil imports. Gas demand shot up significantly between 1973 and 2011, growing from just 17 bcm in 1973 to 78 bcm in 2011 (it peaked at just over 86 bcm in 2005). This growth is almost entirely attributable to the increase in demand for power generation, as indicated in the graph below.

Figure 4.14.6 Natural gas consumption by sector, 1973-2011



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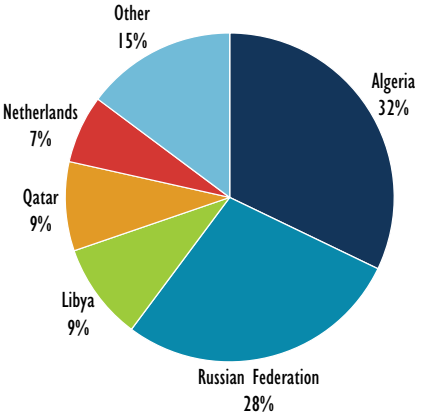
Power generation still accounts for over 33.5% of total natural gas demand in Italy, after a heavy fall in 2012 consumption (-11%). The residential sector is the biggest source of demand growth for natural gas, as it is the preferred choice for domestic uses in new buildings. In the industrial sector, gas consumption has remained relatively stable (although declining slowly), owing both to the high market share that gas had already attained and to the low rates of industrial growth in recent years.

Gas import dependency

Import dependency for natural gas is very high, standing at 88.5% in 2012. Italy's import dependency is set to slowly increase to around 90% by 2018. The vast majority of imports were delivered by pipeline in 2012, with the remaining amount delivered as LNG cargoes. Two countries – Algeria (21.8 bcm) and Russia (19.0 bcm) – account for 60% of Italy's imports, followed by Libya (9%), and Qatar (9%). The Netherlands and Norway are also significant sources of natural gas imports for Italy.

Figure 4.14.7 Natural gas imports by source, 2011



Since May 2000, it has been compulsory to include a flexibility margin of at least 10% in all natural gas import contracts. This flexibility allows for the possibility of importing additional gas during peak periods such as winter cold snaps. Almost half of Italy's natural gas import activity is conducted on the basis of long-term take-or-pay contracts, with an overall duration exceeding 30 years. One-quarter of the import activity is carried out through contracts having a total duration of between 20 and 30 years. The remaining one-quarter of contracts involves durations of less than 20 years.

Gas supply infrastructure

Ports and pipelines

There are four natural gas pipelines (TransMed, Greenstream, TAG, TENP/Transitgas) and three LNG terminals for importing natural gas into Italy.

Two pipeline entry points (Tarvisio and Mazara del Vallo) account for almost 40% of Italy's gas imports. Italy's biggest entry point is the TAG pipeline interconnection through Tarvisio in the northeast of the country, which in 2012 delivered 23.8 bcm of natural gas (maximum capacity of 4.99 mcm/h), equivalent to 35.3% of total gas imports to Italy. The TransMed interconnection to Tunisia through Mazara del Vallo in Sicily is also significant, delivering 20.8 bcm (30.8% of total gas imports to Italy) in 2012 (maximum capacity of 4.40 mcm/h).

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Italy also has two LNG regasification terminals in operation: at Panigaglia in Liguria; and at the North Adriatic Sea offshore terminal near Rovigo, which began operations in 2009. A third LNG terminal is under construction at Livorno in Tuscany.

Storage

Gas storage infrastructure plays an important part in the Italian gas market. Storage is filled in the low-demand summer months and emptied during the peak-demand winter months. Ten storage fields operate in Italy, totalling about 9 bcm of commercial working capacity. Given that peak winter demand in recent years has stood at around 450 mcm/d, Italy's maximum withdrawal capacity can theoretically cover almost 70% of peak winter demand (assuming perfect interconnectivity).

The long authorisation process, which includes environmental impact assessment requirements, has become a barrier to the creation of new storage capacity. Access to storage facilities is based on regulated third-party access, and published tariffs are established by the regulatory authority in line with criteria established by the government. The tariffs include a commodity charge, a strategic storage fee, and charges for volume, injection and withdrawal capacity.

Emergency policy

Italy's natural gas emergency response policy provides for mandatory security measures in the national gas system (e.g. dispatching rules) aimed at reducing price fluctuation, increasing security of supply, co-ordinating the storage system and reducing the vulnerability of the gas system.

Italy was severely affected by a disruption of gas supplies over the winter of 2005-06, and has since taken significant measures to better prepare for another such situation. The Ministry of Economic Development updated its legislation regarding specific emergency procedures in 2013, with the adoption of the emergency plan as provided for by European regulation.

The update establishes the roles of the players involved, the system monitoring procedures and the measures to be taken by the ministry in the case of a crisis. A specific "technical emergency committee for the gas system" within the ministry was designed to adopt the most appropriate measures available. The emergency procedures list includes a series of measures for increasing gas imports and reducing gas consumption.

Emergency response measures

Each year, minimum natural gas storage volumes are set by a Ministry of Economic Development notice. Storage levels are expected to be sufficient to cover the equivalent of a 50% disruption of peak capacity at the main national entry point for a period of 60 days, and are determined on the basis of imports through the system's major entry points. All natural gas imports from outside the European Union are included in this calculation.

Italy's strategic stocks, located in the north of the country, stood at around 4.6 bcm ahead of the 2012-13 winter. Ownership of the natural gas stocks resides with the storage companies.

During the gas crisis in the winter of 2011-12, the Italian government decided, among other measures, to curtail demand from industrial customers directly connected to the transmission network. This affected 403 users and led to savings of 15.6 mcm/d from 6 to 13 February. Other demand restraint measures also affected 260 remotely controlled customers and led to further savings of 9 mcm/d from 7 to 9 February. Stock was also released from the strategic natural gas reserves to help alleviate the gas shortage.

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A decree passed in April 2013 by the Ministry of Economic Development introduced new procedures (an emergency plan) for coping with supply crises involving the whole gas system. Furthermore, in order to diversify strategies, a mechanism of fuel switching for power generation is ready to be implemented. Such a measure was also used in 2012, but the updated procedures will work in a more flexible and cost-effective way, as provided for by a new ministerial decree passed in September of this year.

Fuel switching by power generators during the gas crisis in the winter of 2011-12 guaranteed savings in gas volume equal to 18 mcm/d. The amount of electricity previously generated from gas-fired power plants was instead produced by plants fuelled with combustible oil. Although successful in terms of natural gas savings, these measures were very expensive in environmental terms because the oil-fired plants are old and highly polluting, and in terms of direct cost because of high maintenance and fuel storage replenishment costs.

Options for fuel switching outside the transformation sector are limited, however, as only 0.5% of the industrial load can operate on fuels other than gas. Furthermore, large industrial facilities are not legally required to have alternative fuel available.

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Japan

Key data

Table 4.15.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	13.3	17.5	18.5	18.1	17.4	16.5	16.1
Demand (kb/d)	5 315.3	5 515.4	5 327.9	4 455.4	4 471.2	4 714.8	4 354.6
Motor gasoline	738.5	998.9	1 045.6	1 003.8	976.9	978.2	-
Gas/diesel oil	1 112.3	1 241.3	1 149.8	842.3	820.8	826.3	-
Residual fuel oil	898.3	653.2	581.5	394.0	439.2	562.1	-
Others	2 566.2	2 622.0	2 551.1	2 215.4	2 234.3	2 348.1	-
Net imports (kb/d)	5 302.0	5 497.9	5 309.4	4 437.3	4 453.8	4 698.3	4 338.5
Import dependency (%)	99.7	99.7	99.7	99.6	99.6	99.7	99.6
Refining capacity (kb/d)	4 198.0	4 997.7	4 706.9	4 896.5	4 896.5	4 896.5	-
Oil in TPES (%)**	57	49	47	41	45	46	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.15.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	2 119	2 499	3 140	3 343	3 334	3 177	2 431
Demand (mcm/y)	58 107	83 499	88 067	109 344	126 358	130 737	130 622
Transformation	39 526	55 840	52 768	64 244	80 304	0	-
Industry	4 728	6 266	8 153	9 666	10 372	0	-
Residential	8 696	10 640	11 081	10 849	10 841	0	-
Others	5 157	10 753	16 065	24 585	24 841	0	-
Net imports (mcm/y)	55 988	81 000	84 927	106 001	123 024	127 560	128 191
Import dependency (%)	96.4	97.0	96.4	96.9	97.4	97.6	98.1
Natural gas in TPES (%)	10	13	14	17	22	23	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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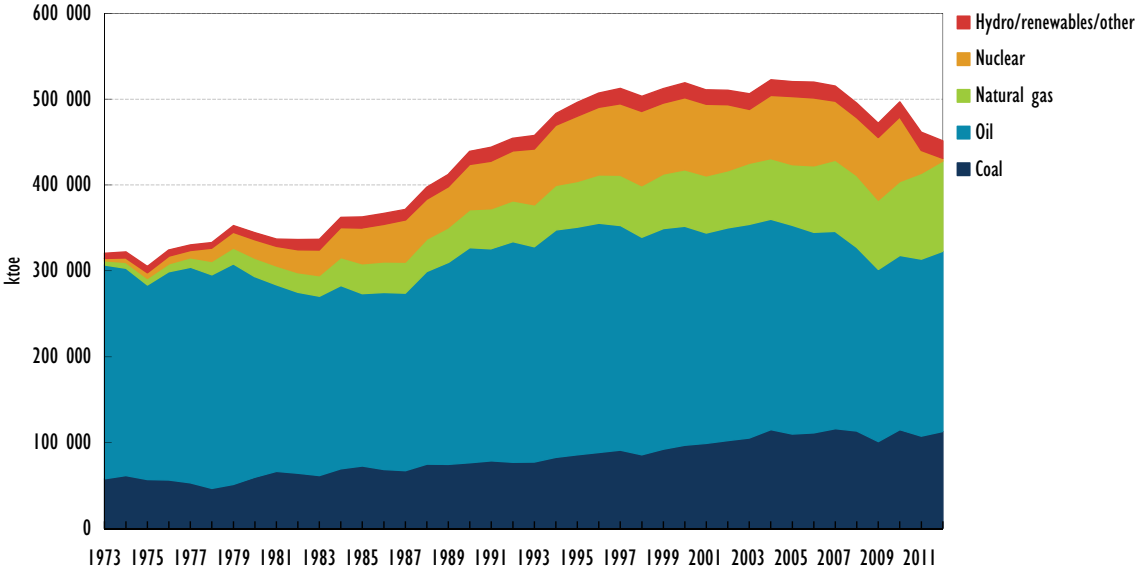
Figure 4.15.1 Total primary energy source (TPES) trend, 1973-2012



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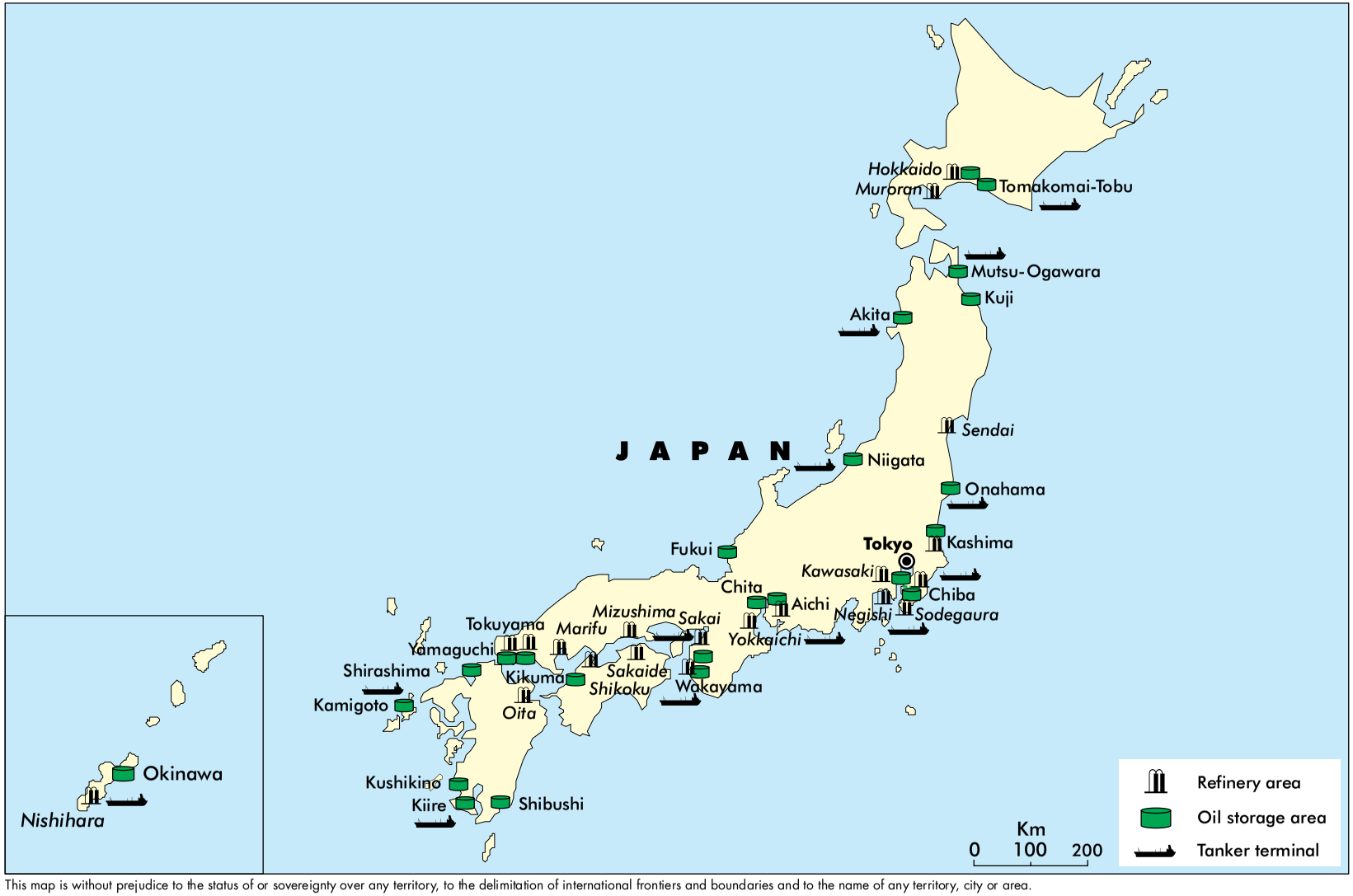
Map 4.15.1 Oil infrastructure of Japan



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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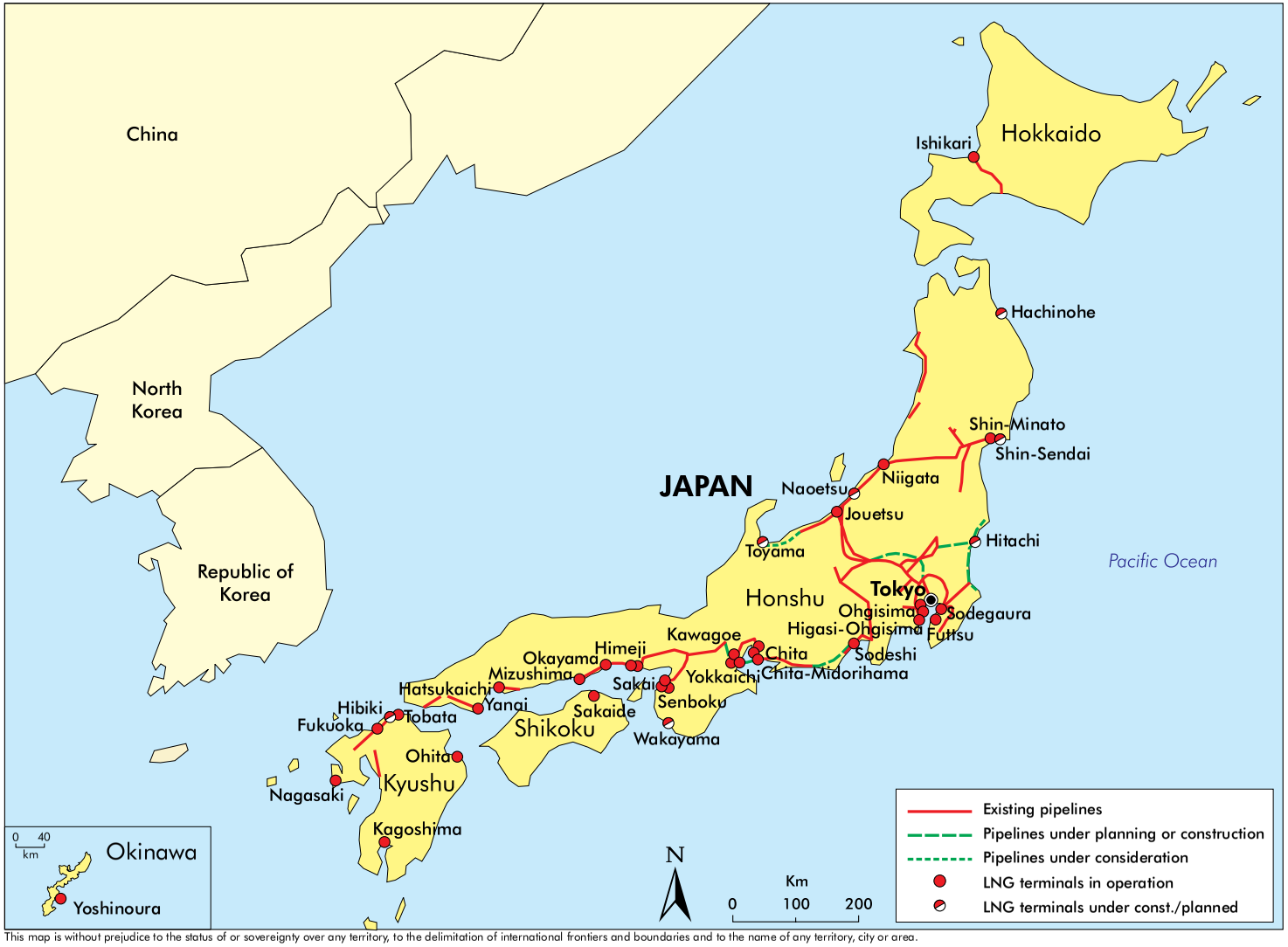
Map 4.15.2 Gas infrastructure of Japan



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Country overview

Oil remains the most significant energy source in Japan, accounting for some 46% of the country's total primary energy supply (TPES) in 2012. Japan's oil demand steadily decreased from 5.7 million barrels per day (mb/d) in 1997 to 4.5 mb/d in 2010. However, its oil demand increased to 4.7 mb/d in 2012 because of the Great East Japan Earthquake in March 2011 and its subsequent impacts. The transport sector represented around 36% of total consumption in 2011, while the industry sector accounted for 29%. A significant proportion of the industry sector's oil demand comes from the chemical industry.

Of the 4.8 mb/d of oil imported by Japan in 2012, 3.5 mb/d consisted of crude oil, 209 thousand barrels per day (kb/d) of natural gas liquids (NGLs) and feedstocks, and some 1.2 mb/d of refined products. About 83% of Japan's crude oil imports in 2012 came from the Middle East. The country has 27 operational refineries with a total crude distillation capacity of around 4.5 mb/d.

Japan meets its 90-day stockholding obligation to the International Energy Agency (IEA) by holding government emergency stocks and by placing a minimum stockholding obligation on industry. The primary role of the Japan Oil, Gas and Metals National Corporation (JOGMEC) is to manage public stocks under the Oil Stockpiling Act, while industry (refineries, specified distributors and importers) is obliged to hold the equivalent of 70 days of their daily imports, sales or refinery production, based on the average of the previous 12 months. The public stocks mostly consist of crude oil, but the government has expanded its emergency inventory to include four categories of refined products – gasoline, kerosene, fuel oil and diesel oil.

Japan held 596 mb of oil stocks at the end of April 2013, equal to 153 days of 2012 net imports (84 days of government stocks and 69 days of industry stocks). Around 70% of total stocks were held in the form of crude oil. Japan has consistently met its minimum IEA stockholding obligation.

The share of natural gas in the country's TPES increased significantly from 17% in 2010 (before the March 2011 earthquake) to 23% in 2012, because of growing demand from the electricity generation sector. Japan's demand for natural gas steadily increased from 26 bcm (71 mcm/d) in 1980 to around 109 bcm (298.6 mcm/d) in 2010, to 124 bcm (340 mcm/d) in 2012. Japan's domestic natural gas production is limited, with production of around 3.3 bcm in 2012.

Natural gas supply sources to the country are well diversified. In 2012, Australia was the largest supplier, representing 20% of total imports. As Japan has no cross-border pipelines, the country imported natural gas through 31 LNG terminals with around 10 billion cubic metres (bcm) of natural gas storage capacity.

Key elements of Japan's overall gas security policy are: diversifying its long-term supply contract portfolio; ensuring that long-term contracts include flexibility to increase imports during an emergency; and using voluntary commercial LNG stocks in industry. Even though industry is not obliged to hold any emergency gas stocks, industry has commercial stocks equivalent to about 20 to 30 days of consumption.

There is no single gas transmission system operator (TSO) in the country as the trunk line networks have developed separately around LNG terminals and are not necessarily connected to each other. Each gas company is asked to ensure its natural gas supply to its distribution area.

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Oil

Market features and key issues

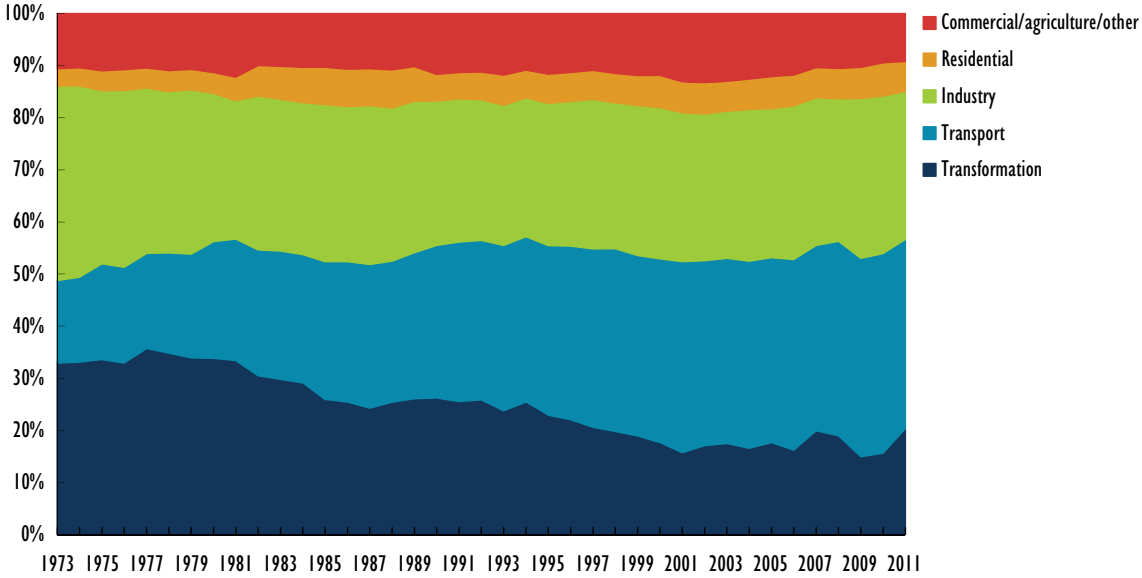
Domestic oil production

Japan produced only 17 kb/d of crude oil in 2012, which was equivalent to 0.3% of total consumption. Almost all Japanese oil consumption is covered by imports.

Oil demand

The country's oil demand steadily decreased from 5.7 mb/d in 1997 to 4.5 mb/d in 2010. However, its oil demand increased to 4.7 mb/d in 2012 owing to the Great East Japan Earthquake in March 2011 and its subsequent impacts. In 2011, around 36% of Japanese total oil demand was consumed by the transport sector, while the industry sector and the transformation/energy sector accounted for 29% and 20% respectively. High oil demand in the industry sector mostly derives from the chemical sector, including petrochemicals, accounting for 65% of total industry consumption.

Figure 4.15.2 Oil consumption by sector, 1973-2011



Demand for all oil products decreased from 2003 to 2012. Demand for gasoline decreased by 5% during the last decade, while demand for diesel dropped by about 19%. Demand for heating/other gasoil also significantly decreased by 40% from 632 kb/d in 2003 to 377 kb/d in 2012.

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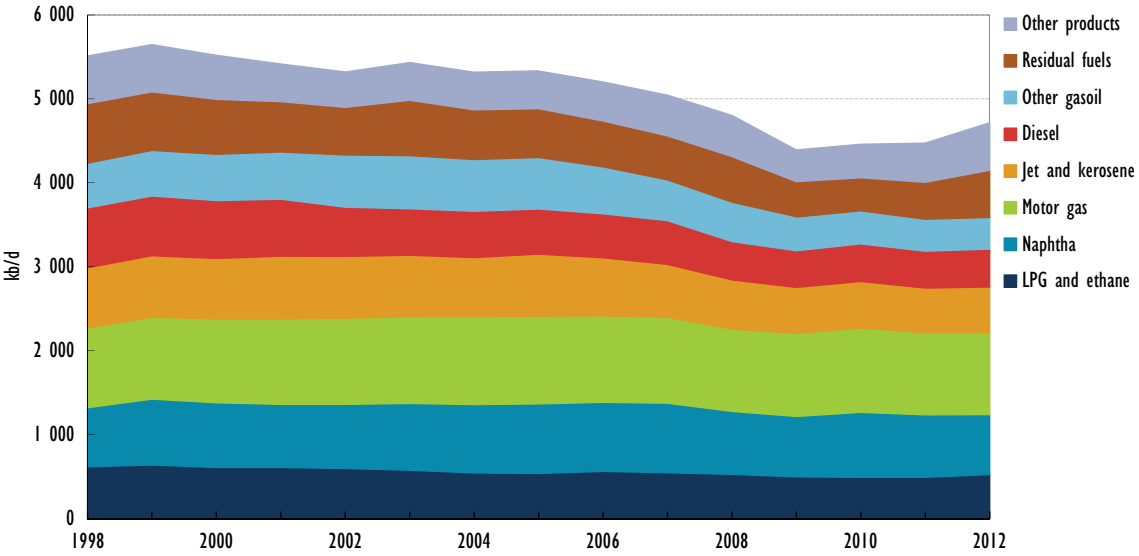
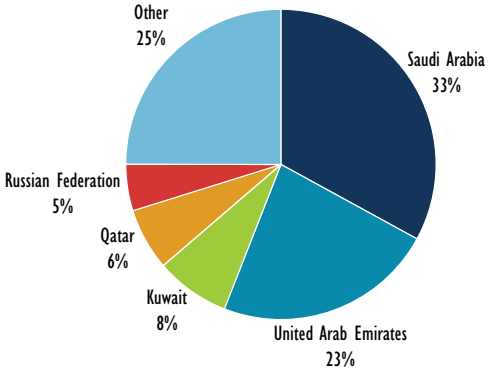
Figure 4.15.3 Oil demand by product, 1998-2012



Imports/exports and import dependency

Japan's oil imports in 2012 were around 4.8 mb/d, consisting of about 3.5 mb/d of crude oil, 209 kb/d of NGL and feedstocks, and 1.2 mb/d of refined products. Saudi Arabia was the largest supply source of crude oil with about 33% of the 2012 total, followed by the United Arab Emirates (UAE) (23%), Kuwait (8%), Qatar (6%) and the Russian Federation (5%).

Figure 4.15.4 Crude oil imports by origin, 2012



In 2012, almost half of refined product imports came from the OPEC countries, followed by OECD countries (27%) and non-OPEC Asia (18%). By country, Korea was the largest supplier of refined products with about 15% of the 2012 total, followed by Qatar (14%), UAE (13%), Kuwait (10%) and Saudi Arabia (10%).

Oil company operations

Refining and distribution of oil products are fully privatised and open to foreign capital companies. As domestic oil demand has continuously decreased in the country, the retail market has been rationalised accordingly. The number of filling stations has been streamlined from over 60 000 in 1995 to 38 777 stations in 2011. Oil companies in the country have also been reorganised in the context of high crude oil prices and severe competition in the overall energy market.

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Refining

In 2012, there were 27 refineries with a total crude distillation capacity of around 4.5 mb/d – a decrease of some 850 kb/d (from 5.3 mb/d) since 2000. This decline in refining capacity occurred against a backdrop of decreasing domestic oil demand.

By company, four major oil companies owned 17 refineries in 2012: Cosmo Oil operates four refineries with a total capacity of 635 kb/d; Idemitsu Kosan operates four refineries (640 kb/d); JX Nippon Oil and Energy operates six refineries (1.2 mb/d); and Tonen General operates three refineries (661 kb/d). Refineries are mostly located close to demand centres of refined products, and eight refineries are located in Kanto Region in order to supply oil products in the region which includes Tokyo.

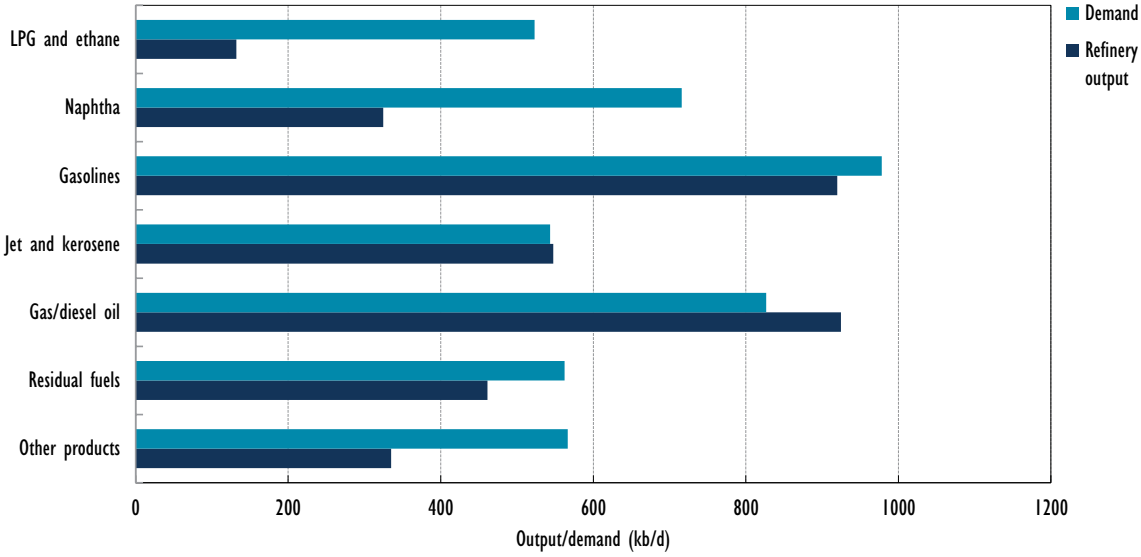
By 2014, three refineries, with a capacity of 440 kb/d in total (amounting to almost 10% of the country's capacity in 2012), are expected to be closed according to the Law on Sophisticated Methods of Energy Supply Structures of 2009.

In 2011, the total crude throughputs were around 198 million kilolitres (kl), averaging 3.4 mb/d. The total utilisation rate of refineries was around 75%, although six refineries had been temporarily shut down by the March 2011 earthquake, which reduced total operational refining capacity to 70%.

In 2012, the refined product output totalled 3.6 mb/d. The main products of the refineries were gas/diesel oil (25%), followed by gasoline (25%), other middle distillates (15%), residual fuel oil (13%), naphtha (9%) and liquefied petroleum gas (4%).

With the exception of jet and kerosene, gas/diesel oil and residual fuels, domestic refinery production is insufficient for meeting demand in the country. In 2012 domestic production of gasoline was able to meet 94% of domestic oil use. Domestic production of naphtha met 44% of domestic demand and LPG/ethane 26%.

Figure 4.15.5 Refinery output vs. demand, 2012



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Ports and pipelines

As Japan is an island country surrounded by ocean, imports of crude oil and petroleum products are undertaken by oil tankers; between April 2010 and March 2011, 837 crude oil tankers arrived at Japanese ports. The country has five main oil ports which are located in Chiba, Yokohama, Yokkaichi, Shibushi and Okinawa. Chiba port unloads crude oil to supply four refineries holding a total distillation capacity of 760 kb/d. Yokohama port supplies imported crude oil to two refineries in Kawasaki, while Yokkaichi port also delivers crude oil to two refineries in the city. Two other oil ports in Shibushi and Okinawa mainly supply crude oil to closely located national stockholding bases.

Oil products are delivered from refineries to consumers mainly by coastal tankers, tank trucks and railroad tankers. There were 574 domestic vessels for oil products transport in March 2011, while 1 644 railroad tankers were also registered. Around 7 000 tank trucks were deployed for domestic transport in 2010.

There is only one oil pipeline in the country, which transports jet fuels from Chiba refinery to Narita International Airport.

Storage capacity

Storage capacity in Japan was estimated at over 900 mb (over 150 million cubic metres) at the end of March 2012. Within the supply chain, private companies own 225 mb of storage capacity for crude oil – mainly located at refineries. The country also has 361 mb of storage capacity for oil products in the refining and distribution sectors.

In addition, JOGMEC operates national emergency crude oil reserves at ten national stockholding bases (40 mcm or about 251 mb) and in 16 industry-leased tanks (15.7 mcm or some 99 mb). National stockholding bases are spread around coastal areas in the country in different forms: 20.5 mcm (129 mb) of stock are held in above-ground tanks at four national stockholding bases; 5 mcm (31 mb) are held in underground rock caverns at three bases; 10 mcm (63 mb) are held in floating tanks at two bases in the south of the country; and 4.5 mcm (28 mb) are held in the form of an inground tank at Akita base.

Decision-making structure

The Petroleum Refining and Reserve Division of the Natural Resources and Fuel Department acts as a secretariat and forms the core of the Japanese national emergency strategy organisation (NESO) during oil supply disruptions, in co-operation with other relevant ministries and industry.

The Oil Stockpiling Act allows the Minister of Economy, Trade and Industry (METI) to make a decision to release government stocks or lower the industry obligation. According to a decision by the minister, the Petroleum Refining and Reserve Division co-ordinates government stock releases with JOGMEC which is responsible for managing the stocks. When lowering the industry obligation, the division co-operates closely with the Petroleum Association of Japan (PAJ).

The government has implemented changes for improvements following the regional shortages of oil products caused by the 2011 earthquake. One of the improvements is to oblige oil companies to jointly prepare emergency oil supply co-operation plans in order to ensure co-operation among companies in supplying oil products to end-users in the event of a disaster.

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Stocks

Stockholding structure

Japan meets its stockholding obligation to the IEA by holding government emergency stocks and by placing a minimum stockholding obligation on industry.

Under the Oil Stockpiling Act, METI delegates JOGMEC to manage government emergency stocks. The country has accomplished its national stockholding target of holding 50 million kl (equivalent to 315 mb) since 1998. JOGMEC also manages around 0.64 million kl (about 4 mb) of national stocks for LPG – accounting for 19 days of imports held at four national LPG stockholding bases in August 2012.

According to the act, refineries, specified distributors and importers are obliged to hold from 70 to 90 days of their average daily imports, sales or refined production from the previous 12 months. Since 1993, the stockholding obligation on industry has been set at 70 days. In addition, LPG importers are obliged to maintain 50 days of daily LPG imports.

METI is responsible for ensuring the implementation of the oil stockpiling obligations. It is empowered to set the quantities of oil to be stockpiled on an annual basis and to supervise the compulsory stocks and their use.

Crude or products

Japan held around 596 mb of oil stocks (321 mb of government stocks and 275 mb of industry stocks) at the end of April 2013 – equal to 153 days of 2012 net imports (84 days of government stocks and 69 days of industry stocks) – to meet its IEA obligation. Around 70% of total stocks were held in the form of crude oil, as crude oil accounted for about 97% of public stocks.

However, according to the amendments of the Oil Stockpiling Act, the government plans to hold up to four days of refined products such as gasoline, kerosene, fuel oil and diesel oil in the national emergency oil inventory.

In terms of industry stocks, crude oil is the main product held in reserve (39%), followed by natural gas liquids (NGLs) and feedstocks (24%), middle distillates (13%) and motor gasoline (5%). Industry may substitute crude oil for oil products which it is obliged to hold.

Location and availability

Japan has a bilateral agreement with New Zealand that allows it to hold stocks on New Zealand's behalf (using petroleum reserve ticket contracts) that count towards New Zealand's IEA obligation.

Public crude oil stocks are widely dispersed at ten national stockholding bases and in 16 domestic private terminals. Around 70% of public stocks are held at national stockholding bases. Compulsory stocks are commingled with commercial and operational stocks.

Monitoring and non-compliance

METI can conduct on-site inspections of stockholding facilities to monitor the physical availability of compulsory stocks.

In the case of a failure to comply with compulsory stockholding obligations, companies can be sentenced to up to one year in prison or fines up to JPY 3 million (or around USD 32 000).

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Stock drawdown and timeframe

The Oil Stockpiling Act requires a decision by the Minister of the Economy, Trade and Industry to draw down public stocks in global supply disruptions or local disruptions because of natural disaster. Upon receiving the stock release order from the minister, METI opens a public tendering process. After completion of the tendering process, JOGMEC is instructed to supply public stocks to the successful bidders. It is estimated that it would take around 10 to 15 days to draw down public stocks after receipt of the instruction from the government. The 2012 amendments to the act also allow the government to loan public stocks to the market.

A decision from the minister is required to lower the compulsory stockholding obligation (CSO). Decisions on how the compulsory stocks should practically be released are made by the stockholder in close co-operation with the PAJ.

Financing and fees

In the fiscal year 2012, the government budgeted JPY 45 billion (around USD 485 million) for maintenance of public stocks managed by JOGMEC. The cost of compulsory industry stocks is basically passed on to final consumers at market prices. JOGMEC, however, provides a loan for industry to purchase a part of the compulsory oil stocks. The government provides industry players covered by the CSO with interest subsidies for purchasing compulsory oil stocks.

Other measures

Demand restraint

Demand restraint is considered as a secondary emergency response measure that could complement an oil stock release in Japan. But, as Japan has abundant amounts of emergency oil stocks, demand restraint measures would only be deployed in the event of a severe oil supply crisis.

Japan's demand restraint measures would range from light-handed measures (e.g. accurate information sharing and energy saving campaigns) to heavy-handed measures (e.g. limitations in oil use in specific industrial sectors, instruction of oil products mediation for end-users and allocation of oil). The latter measures would be taken under the Petroleum Supply and Demand Optimization Act. According to the act, the prime minister can announce the necessary demand restraint measures based on a cabinet council decision.

To monitor these actions, the government is requested to report to the parliament on the implementation status of demand restraint measures which the prime minister has announced. The METI and relevant ministries monitor measures through regular reports from the oil industry.

Fuel switching

Short-term fuel switching from oil to other fuels is not regarded as an emergency response measure in Japan, as the country had only 2.5 kb/d of potential fuel-switching capacity in 2010. In addition, the government has no legal authority to oblige power generators to switch fuels.

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Other

Japan produced only 17 kb/d of crude oil in 2012, which was equivalent to 0.3% of total consumption. Although this is estimated to increase by 10% to 15%, it is too little to cover domestic oil demand.

Gas

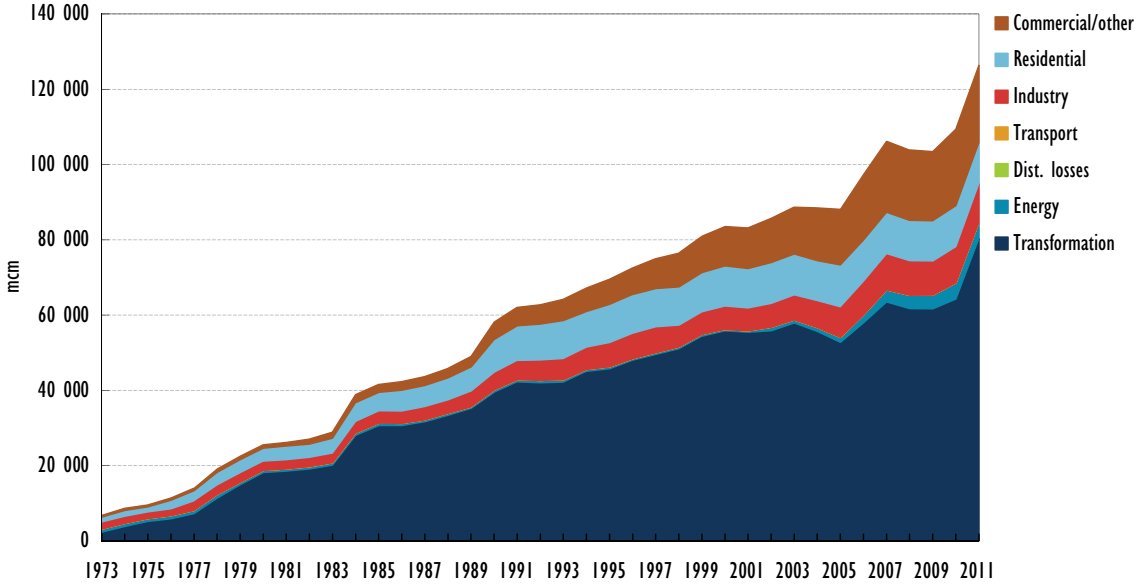
Market features and key issues

Gas production and reserves

In 2012, indigenous natural gas production totalled 3.3 bcm, which accounted for about 3% of total domestic natural gas demand.

Gas demand

Figure 4.15.6 Natural gas consumption by sector, 1973-2011



Japan's demand for natural gas has steadily increased from 26 bcm (71 mcm/d) in 1980 to 109 bcm (298.6 mcm/d) in 2010 and to 124 bcm (340 mcm/d) in 2012.

In 2011, the transformation sector was the largest consumer of natural gas in Japan, representing about 64% of the country's total gas consumption, while the commercial/other sector and the residential sector represented 16% and 9% respectively. The Japanese monthly peak gas demand stood at 11.8 bcm per month in January 2012. Daily peak demand was recorded in February 2012, totalling around 401 mcm/d.

In order to compensate for nuclear outages, natural gas use in power generation significantly increased from 27% of total electricity generation in 2010 to 41% in 2012.

Gas import dependency

Japanese gas demand is mainly supplied by imports in the form of LNG. The country's total natural gas imports in 2012 amounted to 121.6 bcm (333 mcm/d). Natural gas

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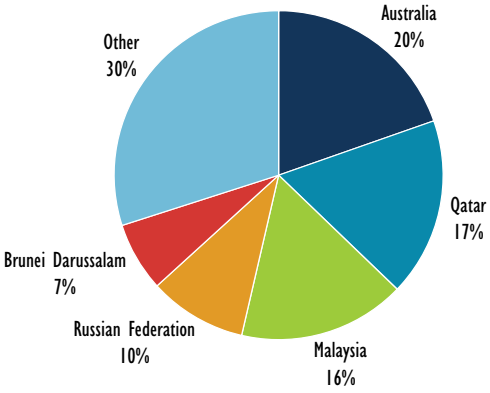
imports in 2012 significantly increased by 23% from 99 bcm in 2010 because of a strong gas demand in power generation.

Figure 4.15.7 Natural gas imports by source, 2012



Natural gas supply sources to the country are widely diversified. In 2012, Australia was the largest supplier, representing 20% of total imports. Qatar (17%), Malaysia (16%), Russia (10%) and Brunei (7%) are other key gas supply sources for Japan.

Gas company operations

The majority of natural gas is imported by seven electricity companies for power generation. The share of the power companies in total LNG imports increased from 62% in 2010 to 65% in 2011. These electricity utilities import their gas independently from the city gas industry.

City gas companies sold around 35.9 bcm to 29 million consumers throughout the country in 2011. Around 27.4 million customers (94%) were residential consumers accounting for about 27% of total city gas sales, while over half of city gas was consumed by industry.

The city gas industry is fragmented into many vertically integrated regional companies. In September 2012, there were 209 general gas utilities. According to data on gas sales volumes, the four major gas utilities – Tokyo Gas, Osaka Gas, Toho Gas and Seibu Gas – held a combined market share of 72% in 2011. Tokyo gas had a share of 34%, Osaka Gas 25%, Toho Gas 11% and Seibu Gas 2%.

Gas supply infrastructure

Pipelines

Japan has no cross-border gas pipelines. Total gas pipeline length accounts for 249 786 km through the country. Around 86% of gas pipelines are low-pressure grids for local distribution, while only 4 772 km are for high pressure. Although there are around 43 main interconnection points between areas, the trunk line networks are not necessarily connected to each other as they have developed separately around LNG terminals.

There is no single operator of the national transmission system in the country, as the trunk line networks are not necessarily connected each other. Each industry (mainly electricity utilities and city gas companies) owns and operates its gas pipelines. Third-party access to trunk pipelines and distribution networks was introduced in 2004 and is to be individually negotiated by parties proposing to supply customers, although the

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lack of interconnections between regions may limit the ability to increase competition through third-party access.

Storage and LNG terminals

While the country has no underground storage for natural gas in its gaseous state, Japan has 31 operational LNG receiving terminals with a total LNG storage capacity of over 16 mcm (equivalent to around 10 bcm of natural gas storage capacity). The country's total storage capacity meets close to 30 days of domestic natural gas consumption.

The country plans to build new LNG facilities or expand storage capacity of existing terminals, which will give the country a further 3.5 mcm of LNG storage capacity in total (equivalent to 2.2 bcm of natural gas) in the near future.

LNG terminals are owned and operated by electricity utilities, city gas companies, other industries such as steel company, and local governments. Electricity companies own close to half of total LNG storage capacity, followed by gas utilities (over 40%). Of the 31 operational LNG terminals, 11 are co-sponsored by power companies, gas utilities, industry or local governments. As of February 2012, the total nominal regasification capacity in LNG terminals represented around 252 bcm of natural gas per year (or 690 mcm/d) with 238 vaporisers.

Emergency policy

Key elements of Japan's overall gas security policy are: diversifying its long-term supply contract portfolio, ensuring the flexibility of increasing imports in contracts in an emergency situation, and using voluntary commercial LNG stocks in industry. The largest natural gas supplier, Australia, represented around 20% of Japan's total imports in 2012.

The Gas Business Act (1954) sets the standard of market activities for natural gas. According to Article 25, gas utilities are obliged to compile and submit gas supply plans to the government every fiscal year. The gas supply plans cover gas supply and demand in a certain period, and the plans are evaluated by the government.

There is no legal obligation for industry to hold emergency stocks in the form of natural gas, LNG or alternative fuels in the country.

Japan has not established a NESO structure for natural gas supply disruptions. However, the divisions in charge of natural gas emergency response at the Agency for Natural Resources and Energy (ANRE) – including the Gas Market Division – are supposed to take the leading roles in co-ordinating the necessary action and liaising with industry.

There is no single transmission operator in the country, as the trunk line networks have developed separately around LNG terminals and are not necessarily connected to each other. Each gas company is obliged to ensure its natural gas supply to its distribution area.

Emergency response measures

Even though industry is not obliged to hold any emergency gas stocks, electric power companies and city gas companies hold a certain amount of commercial stocks. The companies adjust the level of commercial stocks to meet around two weeks of natural gas demand in normal times as well as in times of high demand. As a result, when the country's peak monthly gas demand was recorded in January 2012 with 11.8 bcm, stock levels at the end of the same month and during the following month were maintained at 5.9 bcm and 5.5 bcm respectively. This indicates that the country's commercial stocks

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covered between 13 and 16 days of domestic consumption even in a time of such high demand.

In the event that LNG import is disrupted, importing companies (seven electricity companies and less than ten gas utilities) can also allocate their gas imports through reciprocal backup supply.

Japan has no legislation allowing the government to oblige electricity utilities to switch fuels from natural gas to other fuels. The country has 22 dual-fired power generation units with a total generating capacity of 9 gigawatts (GW) as of 2012. However, it has very limited impact to reduce gas demand in a gas supply shortage, as more than 350 terrawatt hours (TWh) of electricity are generated by natural gas.

During a supply disruption, TSOs will reduce gas supplies according to interruptible contracts. Tokyo Gas, which has around 34% of total market sales of city gas, reduces gas supply to its customers consuming over 0.5 mcm per year with the exception of priority customers such as hospitals, welfare institutions and government offices. Tokyo gas also has over 200 portable air-mixed propane gas generators to temporarily supply gas for priority consumers.

In order to strengthen resistance to disasters such as earthquakes in particular, the Japanese gas industry has replaced old low-pressure gas pipes with polyethylene pipes and high seismic resistant pipes. For the prevention of secondary disasters, it has also been building a shutting-off system which uses block formations and devices for automatic remote shutdown.

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The Republic of Korea

Key data

Table 4.16.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	0.0	13.0	9.8	20.9	20.5	21.3	19.4
Demand (kb/d)	1 048.3	2 135.3	2 191.3	2 268.6	2 257.7	2 301.0	2 263.0
Motor gasoline	64.9	170.5	162.9	188.9	190.5	196.3	-
Gas/diesel oil	279.1	379.1	413.9	399.4	393.3	399.9	-
Residual fuel oil	333.1	487.2	433.7	321.3	276.0	266.0	-
Others	371.1	1 098.6	1 180.9	1 359.0	1 397.9	1 438.9	-
Net imports (kb/d)	1 048.3	2 122.3	2 181.5	2 247.7	2 237.2	2 279.7	2 243.5
Import dependency (%)	100	99.4	99.6	99.1	99.1	99.1	99.1
Refining capacity (kb/d)	867.0	2 540.1	2 576.5	2 790.0	2 790.0	2 790.0	-
Oil in TPES (%)**	53	53	44	38	36	36	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.16.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	0	0	492	542	453	436	0
Demand (mcm/y)	3 042	18 932	30 477	43 201	46 460	49 955	59 349
Transformation	2 274	6 407	12 362	20 142	22 155	0	-
Industry	81	3 207	4 652	7 688	9 087	0	-
Residential	519	6 853	9 346	10 002	9 848	0	-
Others	168	2 465	4 117	5 369	5 370	0	-
Net imports (mcm/y)	3 042	18 932	29 985	42 659	46 007	49 519	59 349
Import dependency (%)	100	100	98.4	98.7	99.0	99.1	100
Natural gas in TPES (%)	3	9	13	15	16	17	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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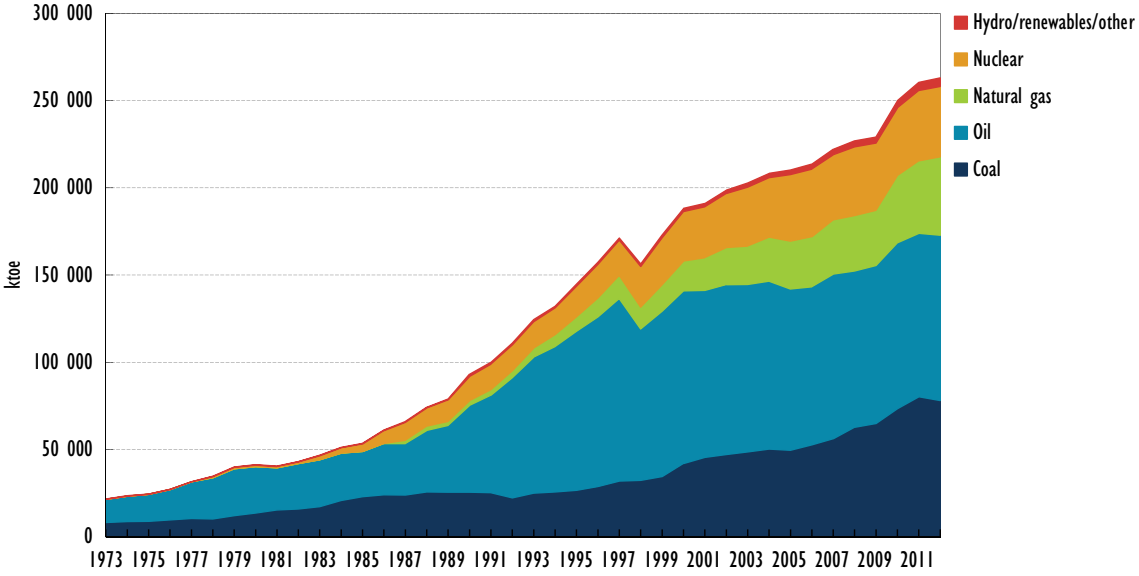
Figure 4.16.1 Total primary energy source (TPES) trend, 1973-2012



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Map 4.16.1 Oil infrastructure of the Republic of Korea

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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Map 4.16.2 Gas infrastructure of the Republic of Korea

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Country overview

Oil has been the dominant energy source in the Republic of Korea, accounting for roughly 36% of the country's total primary energy supply (TPES) in 2012. The share of natural gas in the country's TPES steadily increased from 3% in 1990 to 17% in 2012.

Korea has very little indigenous oil production, which averaged 21 thousand barrels per day (kb/d) in 2012, while Korea's oil demand stood at 2.3 million barrels (mb). Korea is a big consumer of naphtha, mainly for the petrochemical industry. Its oil imports in 2012 were 3.4 mb/d, consisting of 2.5 mb/d of crude oil and 0.8 mb/d of refined products. Korea is highly dependent on the Middle East, which accounted for 85% of its total crude oil imports in 2012. Conversely, Korea exported 1.2 mb/d of oil products in 2012. Around one-third of the product exports went to OECD member countries (mainly Japan and Australia), while the remainder was destined for OECD non-member economies, such as China, Singapore and Indonesia.

The main pillars of Korea's energy security policy are diversification of energy fuel sources (energy mix), diversification of import sources of crude oil and liquefied natural gas (LNG), further build-up of government stocks, expansion of storage capacity for oil and gas and promotion of domestic and overseas exploration and production activities.

Korea meets its stockholding obligation to the International Energy Agency (IEA) by holding government stocks and by placing a minimum stockholding obligation on industry. The Korean National Oil Corporation (KNOC) manages the state-owned oil emergency reserves.

Korea held 176 mb of oil stocks at the end of April 2013. Around 65% of total stocks were held in the form of crude oil.

The use of emergency oil stocks is central to Korea's emergency response policy, which is complemented by the possibility of demand restraint measures. During an emergency, the minister responsible for energy will make the political decision whether to participate in an IEA collective action and on emergency response measures, including oil stock release.

Korea's domestic gas production is negligible. In 2012 it produced about 0.4 billion cubic metres (bcm), which covered less than 1% of its total domestic consumption. Gas demand has steadily increased from 19 bcm in 2000 to 50 bcm (137 million cubic metres per day) in 2012.

As there are no cross-border gas pipelines in the country, all natural gas is imported in the form of LNG. The country has four LNG terminals which have a total send-out capacity of 118 bcm per year (324 mcm/d).

In 2012 Qatar was the largest natural gas supplier (30%), followed by Indonesia (18%), Oman (12%), Malaysia (12%) and Yemen (7%). The Korean Gas Corporation (KOGAS) imports 80% to 90% of LNG though mid- tolong term contracts.

Diversification of supply sources, ensuring LNG supply on the basis of long-term contracts, and securing sufficient natural gas supplies for high seasonal demand are the key elements of Korea's overall gas security policy. Korea has no government natural gas stocks or mandatory industry stocks. An emergency response plan is in place in the event of a gas supply disruption. The plan contains various emergency response measures that would be implemented in separate phases; these include demand restraint and fuel switching.

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Oil

Market features and key issues

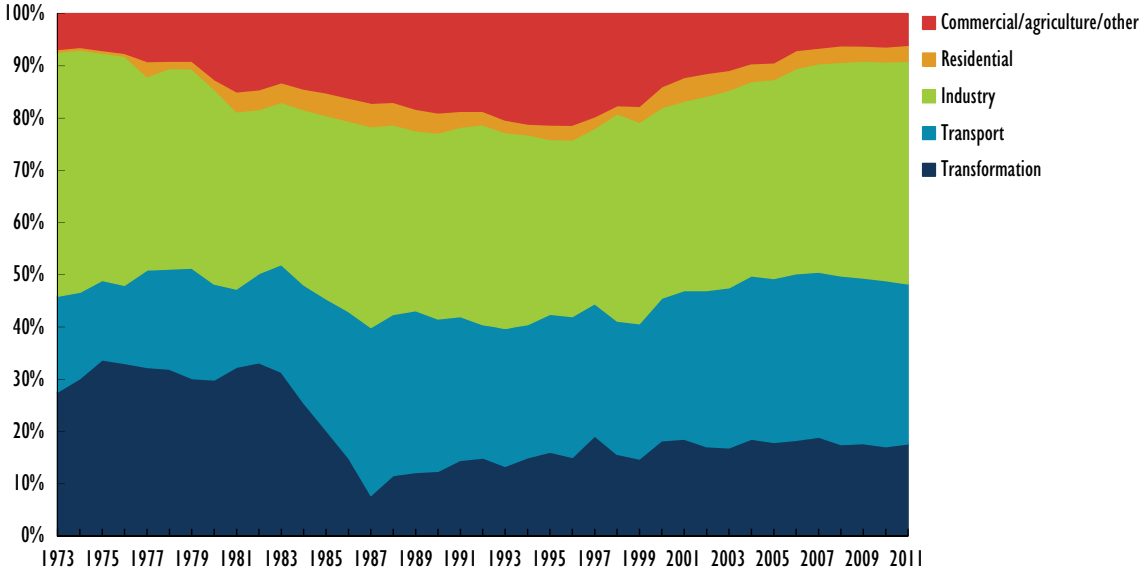
Domestic oil production

Korea has no significant proven reserves of crude oil and the country has very little indigenous crude oil production. Korea's crude oil production in 2012 averaged only 21 kb/d, which covered less than 1% of the total demand.

Oil demand

Korea's oil demand has remained relatively flat over the last decade and stood at about 2.3 mb/d in 2012. The industry sector accounted for 42% of the total oil consumption in Korea in 2011, while the transport and transformation/energy sectors represented 31% and 18% respectively. Korea's total oil demand is forecast to stay relatively flat until 2018.

Figure 4.16.2 Oil consumption by sector, 1973-2011



In terms of oil demand by product, demand for motor gasoline increased by 18% from 2003 to 2012. During the same period, there was a rise in demand for naphtha (51%) and LPG/ethane (10%); demand for residual fuel and kerosene dropped by 41% and 32%.

Korea is a big consumer of naphtha, which is mainly used in the petrochemical industry. Demand for naphtha stood at 1 mb/d in 2012, accounting for about 45% of the total oil demand.

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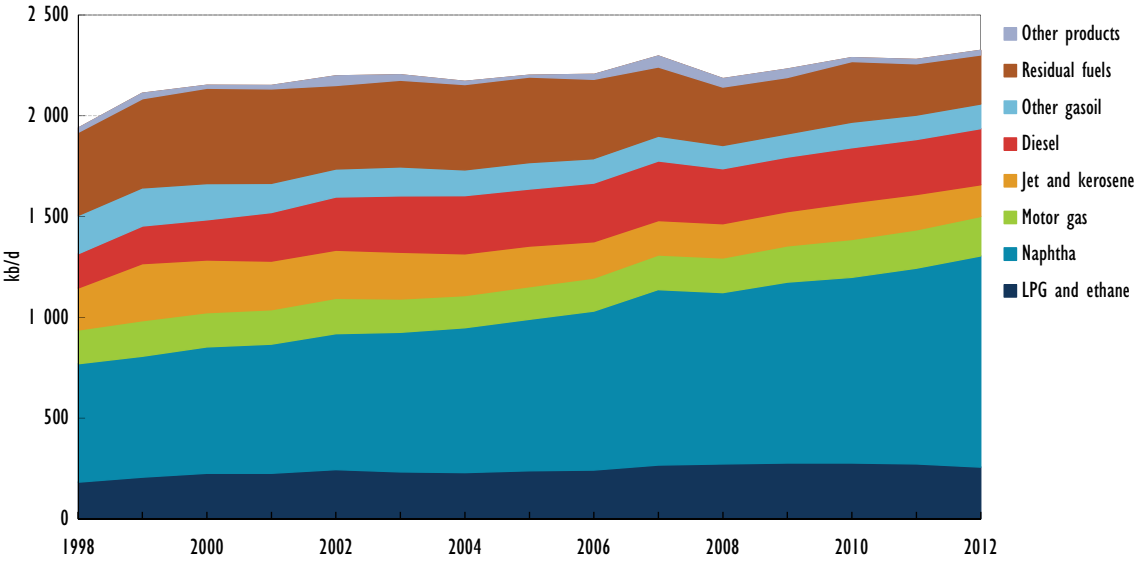
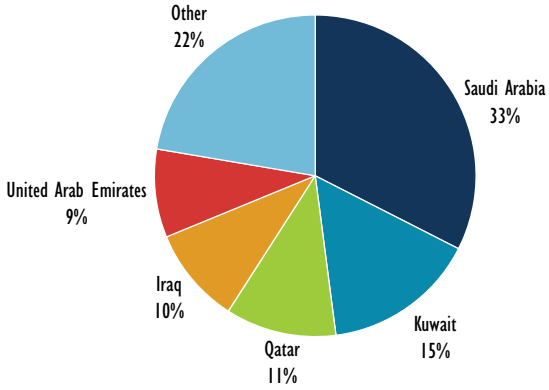
Figure 4.16.3 Oil demand by product, 1998-2012



Imports/exports and import dependency

In 2012, Korea's oil imports were 3.4 mb/d, consisting of about 2.5 mb/d crude oil, 4 kb/d natural gas liquids (NGLs) and feedstock, and around 0.8 mb/d of refined products. Korea is highly dependent for its crude imports on the Middle East, which accounted for around 85% of the total crude oil imports in 2012.

Figure 4.16.4 Crude oil imports by origin, 2012



By country, Saudi Arabia was the largest supply source of crude oil (33% of the total), followed by Kuwait (15%), Qatar (11%), Iraq (10%) and the United Arab Emirates (12%). In 2012, roughly 54% of Korea's refined product imports came from OPEC countries, mainly from the UAE, Qatar, Saudi Arabia and Kuwait; 11% of refined products were imported from India.

As a net exporter of refined products, Korea exported close to 1.2 mb/d of oil products in 2012. Around one-third of the product exports went to OECD countries, mainly to Japan (14%), Australia (6%) and the United States (5%), while the remainder was destined for OECD non-member economies such as China (26%), Singapore (19%) and Indonesia (10%).

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Oil company operations

KNOC is a key player in domestic and overseas oil exploration and production projects. Korea's refining industry is dominated by four major oil companies: SK Innovation, GS Caltex, S-Oil and Hyundai Oilbank. Saudi Aramco is the controlling shareholder of S-Oil.

Daehan Oil Pipeline Corporation (DOPCO) is the major oil pipeline company in Korea and is in charge of the operation of nationwide oil pipeline systems. The main shareholders of DOPCO are the four Korean refiners – SK Innovation (41%), GS Caltex (29%), S-Oil (9%) and Hyundai Heavy Industries (6%) – and the Korean government (12%).

Oil supply infrastructure

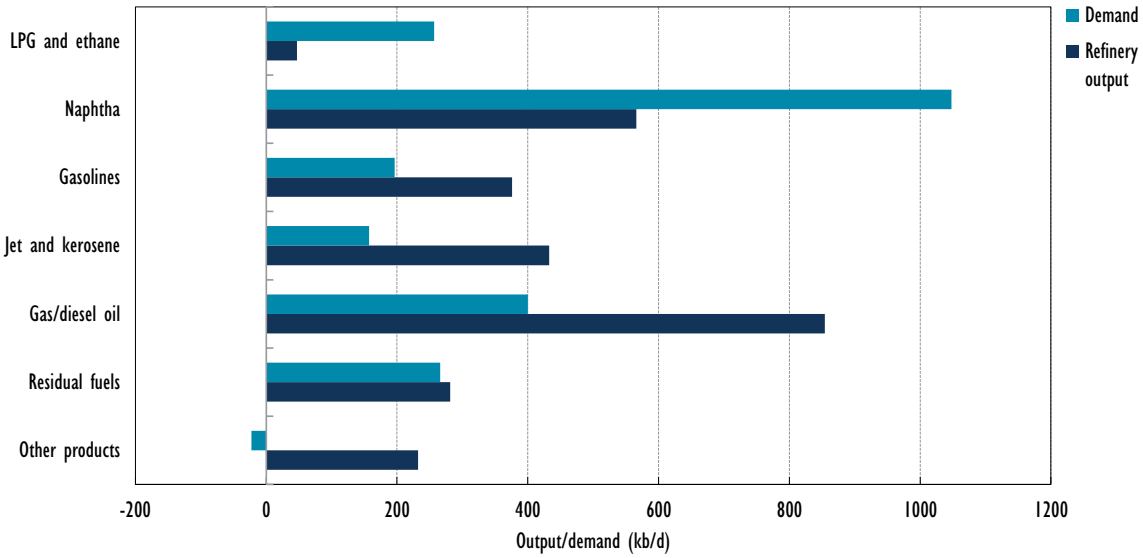
Refining

Korea's five refineries have a combined crude distillation capacity of around 3.04 mb/d. SK Innovation has two refineries, one in Ulsan (840 kb/d) and another in Inchoen (275 kb/d). The other refineries are held by GS Caltex in Yeosu (865 kb/d), S-Oil in Onsan (669 kb/d) and Hyundai Oilbank in Daesan (390 kb/d).

In 2012, the five refineries processed around 993 mb of crude oil (including NGL and feedstocks), which indicates that the overall capacity utilisation rate was about 89%. In 2012, the refined product output totalled 2.8 mb/d.

The composition of production was gas/diesel oil (31%), naphtha (20%), other middle distillates (16%), motor gasoline (13%) and residual fuel oil (10%).

Figure 4.16.5 Refinery output vs. demand, 2012



Korea had a naphtha deficit of around 405 kb/d in 2012, accounting for 42% of total naphtha consumption. Korea also experienced an LPG deficit of some 225 kb/d in 2012 – with an LPG import dependency of over 80%.

Ports and pipelines

Eight main oil port terminals receive Korea's imported crude oils. These terminals are owned by KNOC and the four big refiners and have a total crude import capacity of around 12.3 mb/d. Seven oil port terminals are used for both imports and exports of

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oil products. The total importing and exporting capacity of these terminals is around 20 mb/d.

Korea has no cross-border oil pipelines for exports or imports. Its six oil product pipelines, with a total length of 1 104 km are operated by DOPCO.

The DOPCO pipeline system connects refineries with major cities, airports, military bases and public storage facilities. The utilisation rate of the pipelines was estimated to be approximately 64% in 2010. The pipelines are reversible, and it would take about three days to change the direction of pipeline delivery. Though restrictions do not exist on access to the pipeline network of DOPCO, companies other than shareholders of DOPCO do not make commercial use of it.

Storage capacity

The government started a 30-year project of securing storage facilities for petroleum in 1980; this was completed in May 2010. At the end of 2012, Korea held a total storage capacity of 291 mb (46.2 mcm), which was composed of 146 mb of KNOC's facilities used for government stocks and international joint oil stockpiling, and 145 mb used for industry operation and mandatory industry stocks.

There are nine government storage sites across the country; 87% of this capacity is for crude oil and the remainder is for oil products. About 73% of government storage capacity exists in the form of underground storage facilities, while 27% is in above-ground tanks.

Roughly 39% of the total industry storage capacity was owned by SK Innovation at the end of 2012. The remaining portions were held by GS Caltex (30%), S-Oil (20%) and Hyundai Oilbank (11%).

Decision-making structure

The President of Korea acts as the head of national crisis management, including responding to oil supply disruptions. In practice, the Ministry of Trade, Industry and Energy (MOTIE) is the main and leading governmental body responsible for dealing with oil supply disruptions, and it will closely consult with other relevant governmental entities as well as with domestic industry.

The Energy and Resource Policy Division and the Petroleum Division of MOTIE function as the core body of Korea's national emergency strategy organisation (NESO). In the event of a domestic or global oil supply disruption, the Petroleum Supply and Demand Committee and the Energy Emergency Response Centre (EERC) are set up in MOTIE. The Petroleum Supply and Demand Committee is headed by the minister of MOTIE and is composed of vice-ministers of related ministries and senior executives of relevant companies. This committee is expected to establish a response plan and to make crucial decisions on response actions.

The EERC is led by the head of the Office of Energy and Resources of MOTIE, and is made up of directors-general and directors of MOTIE as well as the vice-presidents of KNOC, KOGAS, the Korean Electric Power Corporation (KEPCO), executives of refineries and the president of the Korea Energy Economics Institute (KEEI). This centre is in charge of implementing the emergency response measures contained in the response plan and of monitoring the oil supply/demand balance.

The Petroleum and Petroleum-Alternative Business Act, the Energy Act and the Energy Use Rationalisation Act authorise the minister of MOTIE to develop an energy demand and supply plan in case of an energy crisis and to decide on emergency response measures

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which include: oil stock release, lowering of the level of compulsory stockholding obligation on industry and demand restraint.

Stocks

Stockholding structure

Korea meets its stockholding obligation to the IEA by holding government stocks and by placing a minimum stockholding obligation on industry. KNOC manages the state-owned oil emergency reserves.

Crude refiners are obliged to hold at least 40 days of stocks, in either crude or products (excluding naphtha), based on a 12-month average of their previous year's sales. Product importers, LPG importers and petrochemical companies are also required to hold at least 30 days of stocks, based on their domestic sales.

KNOC has also promoted the International Joint Stockpile (IJS) Project, inviting and storing crude oil for companies of oil-producing countries. Under the IJS, KNOC rents out storage space to foreign firms, but the IJS also gives Korea first rights to purchase crude oil in case of an oil emergency. Stocks held under this scheme are not counted towards Korea's 90-day commitment.

Crude or products

Korea held 176 mb of oil stocks (90 mb of government stocks and 86 mb of industry stocks) at the end of April 2013 – equal to 238 days of 2012 net imports (122 days of government stocks and 116 days of industry stocks) – to meet its IEA obligation. Around 65% of total stocks were held in the form of crude oil.

Most public stocks were held in the form of crude oil (86%), followed by middle distillates (8%). About 43% of total industry stocks were stored as crude oil while the shares of middle distillates and residual fuel oil were 17% and 10% respectively.

Location and availability

Korea has no bilateral agreements to hold stocks on foreign territory. Emergency oil stocks are held entirely on the national territory.

Domestic refiners generally hold around 60 to 80 days of industry stocks for their operational and commercial purposes as well as to comply with the domestic stockholding requirement. Compulsory industry stocks may be commingled with operational and commercial stocks.

Monitoring and non-compliance

KNOC is responsible for monitoring the quantity, quality and location of industry stocks, as well as for collecting data from industry. KNOC is also authorised to visit commercial storage facilities to verify physical stock levels.

The government has the legal authority to penalise non-compliant companies.

Stock drawdown and timeframe

The minister of MOTIE decides on the drawdown of government stocks and the reduction of the industry stockholding obligation. Upon receiving the stock release order from MOTIE, KNOC will release government oil stocks to Korea's four refining companies in the form of loans. In principle, the amount allocated to each refiner is based upon

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its respective market share. It generally takes KNOC one week to deliver oil stocks to the refiners. Korea's government stocks cannot be legally leased to oil companies and traders other than to the four domestic refiners. Domestic refiners may resell government stocks to third parties if product stocks are leased by KNOC, but they are prohibited from reselling government crude stocks. The pricing scheme for the lease of government stocks is based on international oil prices, the Korean economic situation and other relevant factors, including market interest rates.

For the first week following the government decision to release public stock, the maximum drawdown rate will be 5.2 mb/d, falling to 3.4 mb/d during the second week and 1.7 mb/d during the third week.

The minister of MOTIE can also take the initiative to lower the minimum stockholding obligation on industry. The minister has to bring the proposal forward to the National Assembly for approval, which usually takes more than 20 days.

There is a flexibility mechanism in Korea, called a short-term loan, which allows the government to loan small amounts of government stocks to domestic private companies for short time periods in case of temporary supply disruptions. KNOC can lease such oil stocks within one week to private entities; they, in turn, will be required to reimburse the same amount and type of oil with an agreed interest rate at a later stage.

When stock is released under the IJS Project, foreign companies are required to deliver the crude oil to KNOC within 90 days after KNOC exercises its pre-emptive right to buy crude stocks.

Financing and fees

Construction of government stockpiling facilities has been funded by the budget of the central government. Funds to purchase the oil for public stocks have been provided from both the central government budget and KNOC's internal revenues. Operational costs of government stocks are financed from the central government budget or KNOC's revenues. The average maintenance cost for government stocks in 2012 was USD 0.48 per barrel for crude and USD 1.87 for refined products.

The Korean government does not provide financial support for building compulsory industry stocks. All refiners and importers must self-fund the operational costs of meeting emergency requirements, which are then passed on to consumers.

Other measures

Demand restraint

The minister of MOTIE would make a decision on demand restraint measures according to the severity of the oil supply disruption. Measures are expected to be introduced according to the alert levels in a colour-coded system.

Korea's demand restraint measures would range from light-handed measures to medium-handed and heavy-handed. In Korea, the public sector plays a leading role in energy savings. Major demand restraint measures cover not only the transport sector, but also the residential and industry sectors. Violators would be given a seven-day grace period but would thereafter be fined up to USD 2 800 for contravening the regulations.

Under the colour-coded system on the supply side, it is foreseen that voluntary demand restraint measures would be implemented at its initial stage. If the energy alert level is raised from yellow to orange, mandatory demand restraint measures are expected to be introduced in the public sector. In case the energy alert level reaches red, mandatory demand restraint measures will be applied both in the public and in the private sectors.

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The administration creates and manages inspection units to monitor the implementation of demand restraint measures. The prime minister's office can establish a joint inspection unit with central government departments and public entities in the energy sector. This unit conducts spot inspections for the public sector and publishes the inspection results. MOTIE can also set up a joint inspection unit with local governments and public entities in the energy sector. MOTIE is in charge of monitoring the private sector, and is authorised to impose fines on individuals and entities for non-compliance with mandatory demand restraint measures.

Fuel switching

Short-term fuel switching from oil to other fuels is not regarded as an emergency response measure in Korea, as the share of oil in power generation was only 4% in 2012.

Other

Because of the small amount of indigenous oil production, surge production is not considered an emergency response measure in Korea.

Gas

Market features and key issues

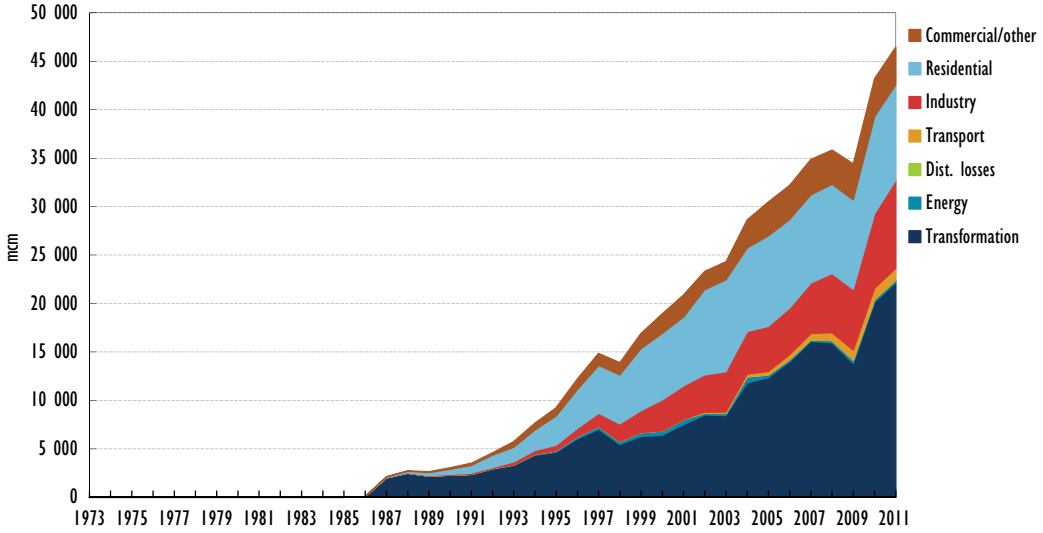
Gas production and reserves

Korea produced about 0.4 bcm of natural gas in 2012, which covered less than 1% of total consumption. Because of its very small indigenous gas production, almost all gas demand in Korea is met by imports.

Gas demand

Korea's gas demand steadily increased from 19 bcm in 2000 to 50 bcm (137 mcm/d) in 2012. In 2011, the transformation sector represented about 48% of the total gas consumption, with the residential sector representing 21% and industry sectors 20%.

Figure 4.16.6 Natural gas consumption by sector, 1973-2011



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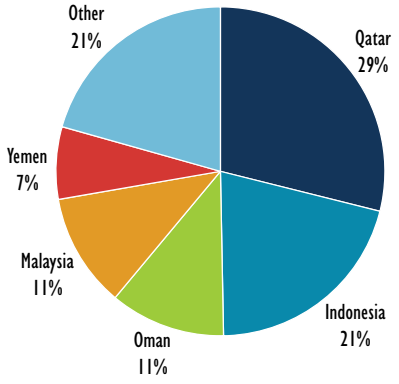
Gas demand in Korea peaks in winter when gas consumption significantly increases for heating and cooking. Daily peak gas demand in 2012 reached 251 mcm/d in January of that year.

Gas import dependency

Korea's total natural gas imports in 2012 amounted to 49.5 bcm (136 mcm/d). KOGAS is the largest LNG import company in the world, with a share of 95% of Korea's total gas imports in 2012.

In 2012 Qatar was the largest supplier of natural gas to Korea (30%), followed by Indonesia (18%), Oman (12%), Malaysia (12%) and Yemen (7%). KOGAS imports 80% to 90% of LNG through mid- to long-term contracts.

Figure 4.16.7 Natural gas imports by source, 2012



Gas company operations

KOGAS is listed on the Korean Stock Exchange, but the major shareholders are government entities, such as the central government (26.9%), KEPCO (24.5%) and local governments (9.6%). As a public enterprise, KOGAS dominates the Korean wholesale market for natural gas in all its aspects, including LNG imports, transmission network, storage and sales activities.

The retail market for gas is made up of 30 private city gas companies with exclusive retail sales rights within their respective regions.

Gas supply infrastructure

Ports and pipelines

Four LNG terminals operate in Korea; three are owned and operated by KOGAS. In addition to KOGAS, the privately owned Pohang Iron and Steel Company (Posco) operates a LNG terminal in Gwangyang to support the power plants of Posco and K-Power.

The four terminals have the capability to handle and supply about 128 bcm per year (350 mcm/d) to the Korean national gas transmission system. The fourth LNG terminal belonging to KOGAS, which is in Samcheok, has a regasification capacity of 2.3 bcm per year; it is estimated to be completed by 2014.

Korea has no cross-border gas pipelines. Its nationwide trunk lines, with a total length of 3 588 km, are owned and operated by KOGAS. It plans to further expand the nationwide pipeline grid and the pipeline network will increase its length to 4 928 km by 2027.

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In September 2008, KOGAS and Gazprom signed a memorandum of understanding (MoU) for Russia to supply the Republic of Korea with 10 bcm of natural gas per year for 30 years via North Korea. North Korea had not given its consent to the construction of an international gas pipeline running through its national territory until a bilateral summit in August 2011, when then President Medvedev of Russia and Kim Jung-Il of North Korea agreed on the development of a gas pipeline to South Korea. It is uncertain however, whether and when the planned pipeline project will materialise. Nevertheless, South Korea and Russia intend to continue to carry forward this project.

Storage

Korea has no underground natural gas storage facilities. Almost all natural gas storage facilities are in the form of LNG storage tanks and their ancillary facilities. At the end of December 2012, Korea had 64 tanks at 4 LNG terminals, with a total storage capacity of 9.3 mcm of LNG (equivalent to 5.8 bcm of natural gas). The total storage capacity was theoretically able to cover about 42 days of average gas demand in 2012. KOGAS owns roughly 97% of the country's total storage capacity at three LNG terminals in Incheon, Pyeongtaek and Tongyeong; the remainder is held by Posco at its LNG terminal in Gwangyang. The maximum withdrawal rate of the three KOGAS storage facilities is about 350 mcm/d.

There are no storage facilities outside of Korea which are accessible to its supply network. Korea's 11th Long-term Natural Gas Supply/Demand Plan envisages that its gas storage capacity will expand from 4.4 bcm to 9.4 bcm in 2017. Under this plan, the Donghae gas field is expected to be converted to a storage facility with a capacity of around 1.5 bcm in 2020.

Emergency policy

Key elements of Korea's overall gas security policy are to diversify supply sources, ensure LNG supply on the basis of long-term contracts, expand storage capacity and secure a sufficient supply of gas for high seasonal demand.

Korea has no government gas stocks or mandatory industry stocks. However, KOGAS has internal criteria for holding gas stocks. KOGAS holds two types of stocks: "minimum stocks" and "safety stocks". Minimum stocks enable storage facilities to operate under normal conditions, whereas safety stocks are used to successfully handle any discrepancy between demand and supply which may arise from unexpected market changes, including sudden gas supply disruptions. The level of the safety stocks varies from some 585 mcm in summer to 920 mcm in winter, depending on the gas demand.

There is no clear legal basis for emergency planning and managing crisis situations that affect the natural gas system in Korea. KOGAS is in charge of Korea's overall domestic supply of natural gas except for large-scale companies which import LNG for their own use. KOGAS, the transmission system operator (TSO), plays a major role in emergency planning and managing crisis situations in consultation with the gas division of MOTIE.

Emergency response measures

In the initial stage of a gas emergency, when a shortage of gas supply is anticipated (Phase I), KOGAS will secure additional volumes of LNG on a commercial basis by securing spot cargoes, cargo swaps and cargo rescheduling. KOGAS has signed master agreements with its major gas suppliers for the supply of LNG in such circumstances. KOGAS has also developed regional co-operation for gas emergency response with Japanese LNG importers, by swapping LNG cargoes.

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In case the measures in Phase I are not sufficient, MOTIE will discuss the situation with major gas users and urge them to reduce gas demand for power generation (Phase II). Subsequently, fuel switching at power plants from gas to other fuels such as fuel oil will be implemented.

If the measures taken in Phase I and II do not restore the state of Korea's natural gas security, according to Article 24 of the City Gas Business Act, the minister may decide on the phased reduction of gas supply to power generators or city gas companies (Phase III). Interruptible contracts do not exist in Korea.

The maximum withdrawal rates of the three storage facilities of KOGAS stand at some 350 mcm/d.

Surge production of natural gas is not regarded as an effective response measure in a gas crisis because of the negligible indigenous gas production in Korea.

Fuel-switching capacity from gas to oil is estimated to be about 2.6 mcm/d of natural gas, which was equivalent to less than 2% of the average gas demand in 2012. In order to implement the fuel switching from gas to oil, some 14 kb/d of fuel oil (Bunker-C) would be required. However, gas-fired power plants in metropolitan areas, such as Seoul and Gyeonggi province, are not allowed to conduct fuel switching because of environmental restrictions. Furthermore, gas-fired power producers are not required to hold a certain amount of backup fuel reserves. In practice, about 21 kb of fuel oil is stored as backup fuel on site.

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Luxembourg

Key data

Table 4.17.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Demand (kb/d)	33.1	48.1	64.8	59.9	61.4	58.8	57.4
Motor gasoline	9.5	13.4	11.6	8.1	8.5	8.2	-
Gas/diesel oil	15.5	26.3	43.2	41.8	43.5	42.2	-
Residual fuel oil	4.3	0.1	0.1	0.1	0.0	0.0	-
Others	3.8	8.3	9.9	9.9	9.4	8.3	-
Net imports (kb/d)	33.1	48.1	64.8	59.9	61.4	58.8	57.4
Import dependency (%)	100	100	100	100	100	100	100
Refining capacity (kb/d)	0.0	0.0	0.0	0.0	0.0	0.0	-
Oil in TPES (%)**	48	70	67	63	61	60	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.17.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	0	0	0	0	0	0	0
Demand (mcm/y)	493	758	1 337	1 364	1 183	1 214	1 455
Transformation	11	75	619	595	476	0	-
Industry	320	314	346	339	311	0	-
Residential	162	177	232	261	215	0	-
Others	0	192	140	169	181	0	-
Net imports (mcm/y)	493	758	1 337	1 364	1 183	1 214	1 455
Import dependency (%)	100	100	100	100	100	100	100
Natural gas in TPES (%)	14	24	29	31	25	26	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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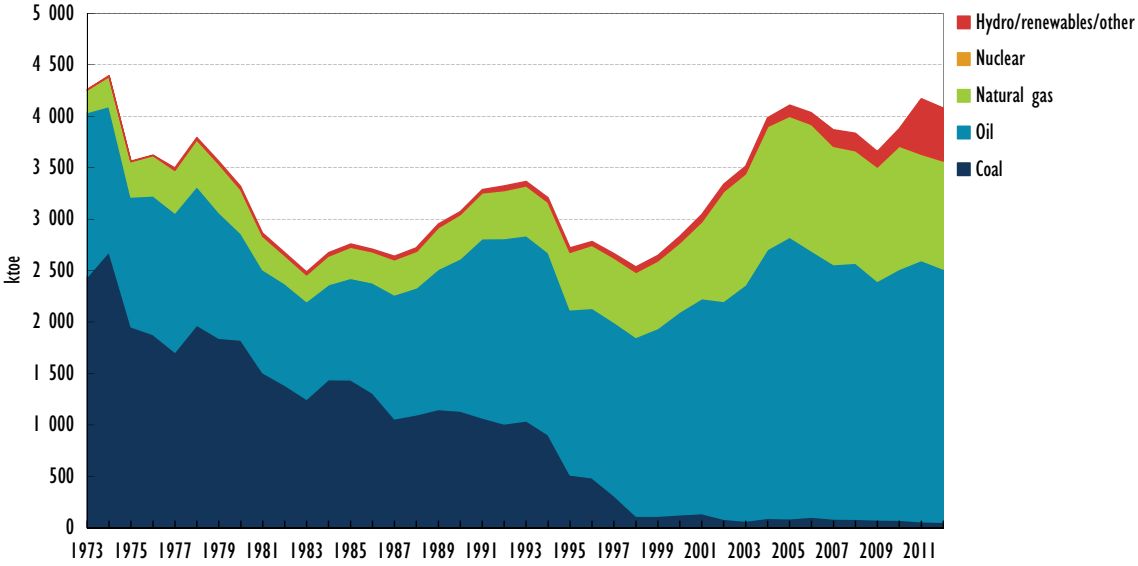
Figure 4.17.1 Total primary energy source (TPES) trend, 1973-2012



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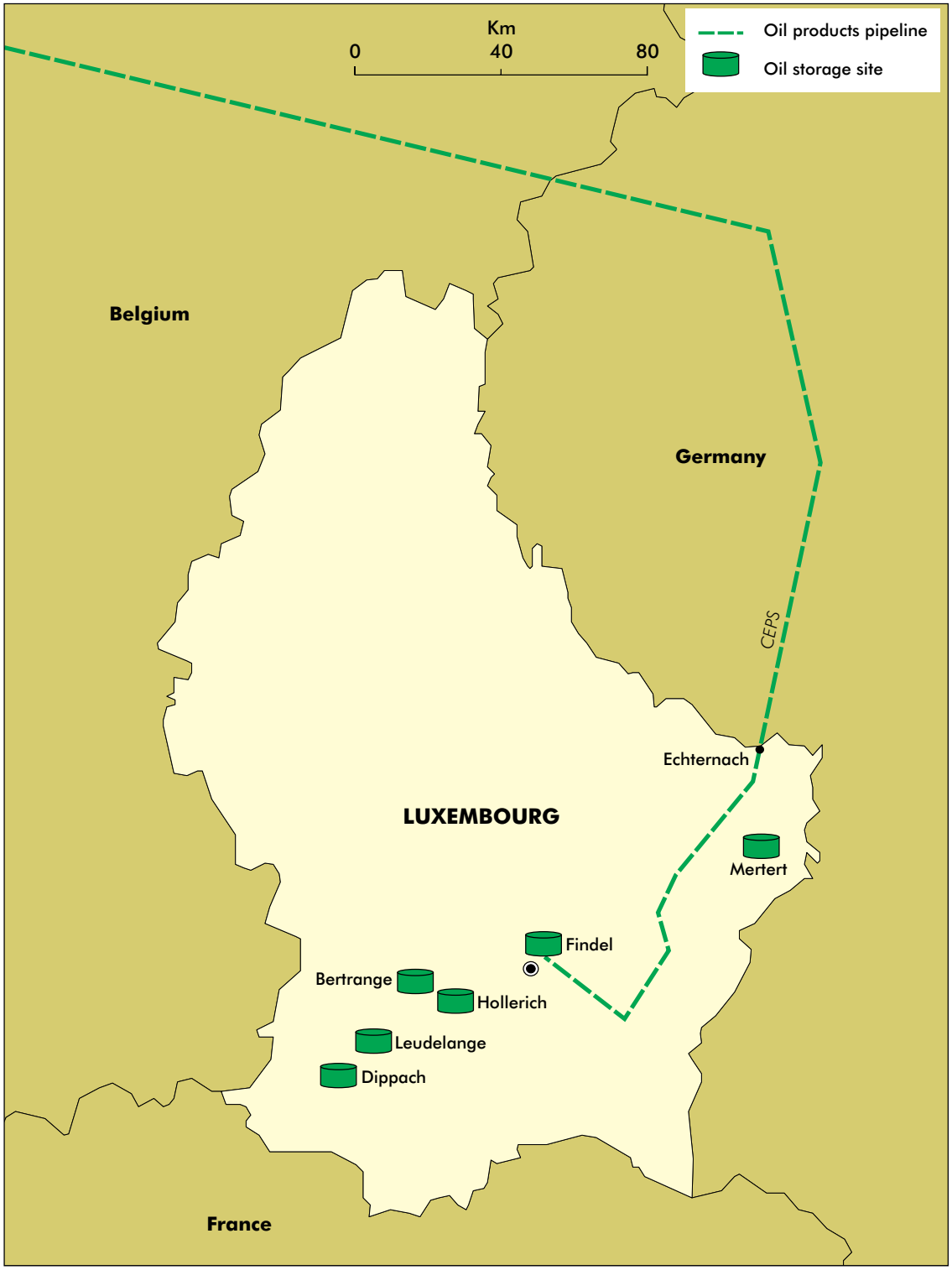
Map 4.17.1 Oil infrastructure of Luxembourg



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Map 4.17.2 Gas infrastructure of Luxembourg

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Country overview

Oil and gas dominate Luxembourg's total primary energy supply (TPES), accounting for 86% of the total. With no domestic oil or gas production, Luxembourg is fully dependent on imports. In the case of oil, this is entirely in the form of refined products as there are no refineries in the country. Oil consumption is concentrated in the transport sector (88%) and primarily in the form of diesel oil. Some 45% of total natural gas is used by the transformation sector, where gas accounts for over 90% of the country's electricity generation.

A large majority of Luxembourg's oil demand comes from cars and trucks crossing its borders to refuel, as lower VAT and excise duties on transport fuels compared to neighbouring countries make fuelling in Luxembourg more attractive. In addition, Luxembourg maintains a maximum price-setting mechanism which limits retailer's abilities to set prices for oil products sold to consumers.

Luxembourg's primary response measure in an oil supply disruption is the use of oil stocks. Oil importers are required to hold a minimum stock cover of 90 days of deliveries to the domestic market, and the Minister of Economic Affairs and Foreign Trade has the legal power to direct the drawdown of these stocks. However, more than 85% of Luxembourg's International Energy Agency (IEA) minimum stockholding obligation is met by stocks held in neighbouring countries, primarily in the form of tickets, because of its limited domestic storage capacity. At the same time, the permits of several important storage depots, concentrating approximately two-thirds of the national storage capacity, will expire by 2019, requiring an even greater portion of stocks to be held abroad. Without action, the country faces a risk in its domestic oil supply chain, making normal fuel deliveries logistically difficult and becoming more vulnerable to disruptions caused by events such as labour strikes or weather conditions which hinder fuel deliveries by road or rail. The Luxembourg government is in the process of reviewing its oil stockholding regime in order to address this challenge and has announced its intention to encourage the building of new storage capacity of 480 000 $m^{3.}$

As Luxembourg has no natural gas storage and no substantial linepack in its transmission grid, there is little supply flexibility within the country to compensate for lost gas supplies. Legislation places the responsibility on the industry for assuring the security of gas supplies through public service obligations. Network operators, suppliers and wholesale customers have the obligation to guarantee the security of supply to consumers and assure that networks are well maintained.

Oil

Market features and key issues

Domestic oil production

Luxembourg has no indigenous oil production and no domestic refinery. Thus it is fully import dependent, with all oil imports coming in the form of refined products.

Oil demand

Oil demand in 2012 was nearly 59 thousand barrels per day (kb/d). This is a decrease from the 64 kb/d in 2005, a year when oil demand peaked after a period of strong demand

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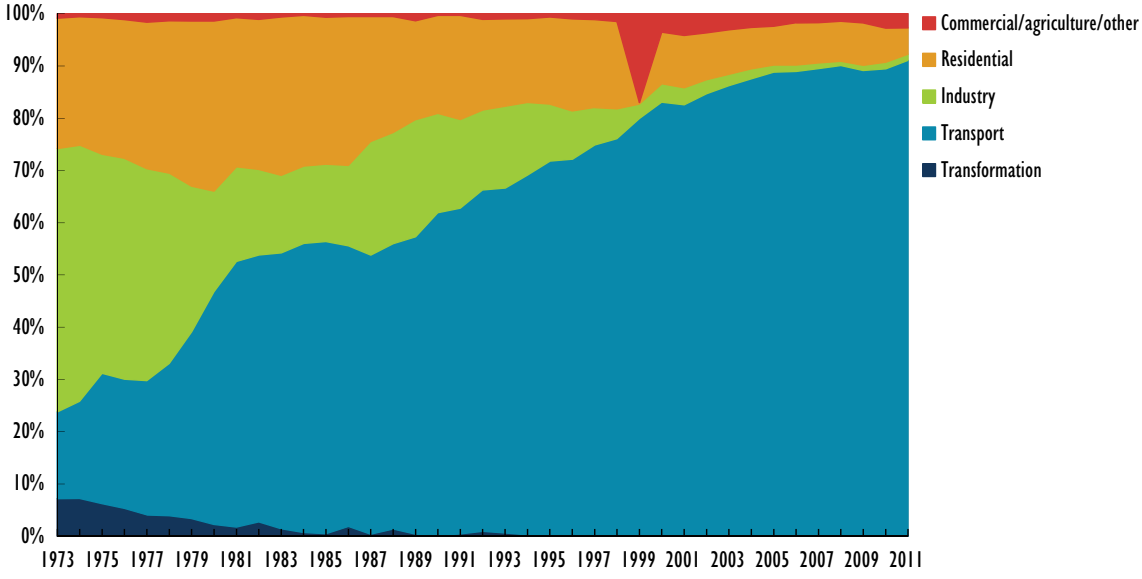
growth. Transport diesel is the single largest component of the country's oil demand, equating to over 42 kb/d in 2012.

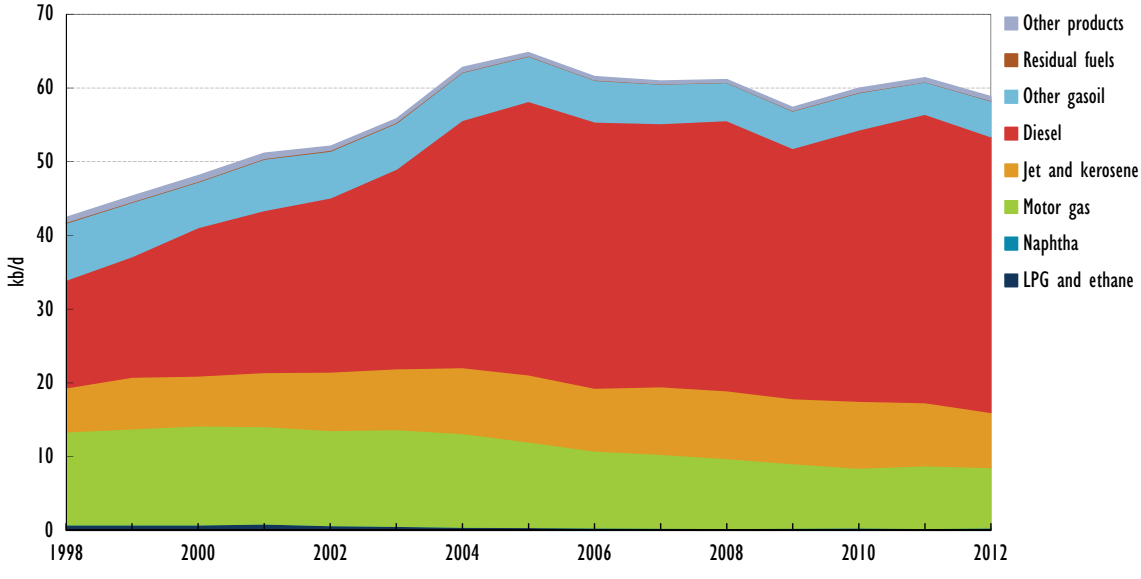
Oil use has grown even more concentrated in the transport sector, representing 91% of total oil demand in 2011, compared to 62% in 1990 and 73% in 1995.

Figure 4.17.2 Oil consumption by sector, 1973-2011



A large portion of Luxembourg's demand for oil is attributed to cars and trucks coming from across its borders. As transport fuels in Luxembourg cost less than in neighbouring countries because of lower taxes on gasoline and diesel fuel, foreign motorists and truckers often cross the border to fill their tanks. This group also includes commuters who enter the country daily from Belgium, France and Germany and represent around 46% of the country's workforce.

Figure 4.17.3 Oil demand by product, 1998-2012



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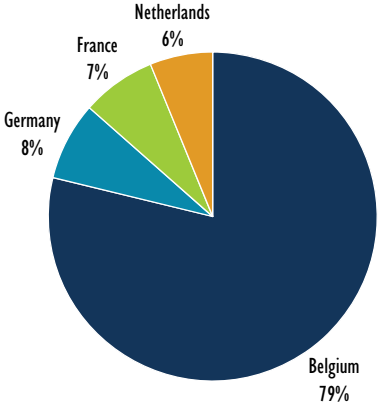
Imports/exports and import dependency

Luxembourg is 100% import dependent, as there is no domestic oil production. With no domestic refinery, all oil imports are in the form of refined products. These essentially come from refineries located in Antwerp, Belgium (roughly three-quarters of total imports), 255 km from Luxembourg City. The rest comes from Germany (8%), France (7%) and the Netherlands (6%). Although the most common method of transport is by road (nearly 40%), a significant proportion of oil products reaches Luxembourg by rail and barge. Only aviation kerosene supplied to the country's airport at Findel is transported by pipeline.

Figure 4.17.4 Oil product imports by origin, 2012



Oil company operations

There are 11 companies operating in Luxembourg's oil market, including three distributors – Q8-Calpam, Petro-Center (selling under the Esso and Mobil brands) and Gulf – and eight retailers (Aral, BP, Q8, Delek, Chevron, Esso, Shell, Lukoil and Total), which operate a total of 240 filling stations in Luxembourg.

Oil supply infrastructure

Refining

There are no refineries in Luxembourg.

Ports and pipelines

The only pipeline in the country is a branch of the Central Europe Pipeline System (CEPS) which supplies aviation kerosene to the country's airport at Findel. The portion of the CEPS in Luxembourg runs a length of 36 km and is constantly filled with about 700 m^3 of fuel. There are no pumps installed along the line in Luxembourg, which has a theoretical flow capacity of 96 m^3 per hour, or some 15 kb/d, with an average flow of around 9.4 kb/d.

Storage capacity

Luxembourg's six main storage facilities are used by oil companies to supply the domestic market. These have a total combined capacity of just over 196 000 m^3, or 1.23 million barrels. The storage sites are: Bertrange, Findel, Mertert, Hollerich, Dippach and Leudelange.The permits of several important depots, concentrating approximately

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two-thirds of the national storage capacity, will expire by 2019. The expiry of these permits might result in a further reduction of the storage capacity on national territory. Therefore, the government has publically announced its intention to encourage the building of new storage infrastructure. A total of 480 000 m^3 of new capacity is planned, with the extension of the Mertert site (by an additional 90 000 m^3) and two new storage sites – Bascharage (90 000 m^3) and Luxembourg-Ouest (300 000 m^3).

Decision-making structure

Emergency response policy is under the responsibility of the Ministry of Economic Affairs and Foreign Trade. Within the ministry, the Directorate for Energy is responsible for maintaining and implementing emergency response measures in the event of an oil supply disruption. It also supervises the guidelines companies are required to follow to ensure the security of natural gas supplies. Its responsibilities include collecting data and monitoring the domestic oil and gas markets, the maximum oil price mechanism and industry's compulsory oil stockholding.

In the event of an oil supply emergency, the Minister for Economic Affairs and Foreign Trade has the legal authority to take a decision on emergency measures "if oil products supply is endangered". This can be either by means of decrees or by notification to individual companies, which could regulate imports, trade and consumption of oil products.

Stocks

Stockholding structure

All oil stocks in Luxembourg are held by oil companies and are typically commingled with commercial stocks.

All oil importers are obliged to maintain stocks of petroleum products equivalent to at least 90 days of deliveries to domestic consumption during the previous calendar year. This applies to each of the three categories covered by the European Union's compulsory stockholding obligations (gasoline, distillates and fuel oil).

Crude or products

Since the country has no refining capacity, all compulsory stock obligations must be held in the form of finished products.

Location and availability

Over 85% of Luxembourg's IEA minimum stockholding obligation is met by stocks held in other EU countries with which Luxembourg has a bilateral agreement. Luxembourg has bilateral agreements with Belgium, France, Germany and the Netherlands.

Most of these stocks are held in the ARA (Amsterdam, Rotterdam and Antwerp) area. For the most part, these stocks are held in the form of short-term ticket agreements.

Monitoring and non-compliance

Oil importers are required to submit reports to the authorities every month. In verifying the accuracy of a company's reported stock levels, police and customs authorities are entitled to check levels at any time, on request of the Minister for Economic Affairs and Foreign Trade. Infringements are punishable by either imprisonment of up to two years or a fine, or both.

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Stocks held outside Luxembourg must be certified by the government of the country in which they are held in order to be counted towards meeting the company's stockholding obligation.

Stock drawdown and timeframe

In the event of an oil supply disruption, the Minister for Economic Affairs and Foreign Trade has the legal authority to draw down compulsory industry stocks. The minister is empowered to authorise participation in an IEA response and the law does not fix a threshold for activating emergency measures. A decision to draw down stocks is expected to take two or three days. This would be organised by means of ministerial decrees as a general measure, or by individual notification to stockholding companies.

The release and pricing of compulsory stocks onto the market would be implemented by an emergency committee, set up at the time, consisting of government officials, oil company executives and consumer representatives.

The physical delivery of stocks to market after the decision for release is expected to take one week. The monitoring mechanism to ensure that companies draw down sufficient stocks to meet IEA requirements would be the standard oil market statistics, completed by companies on a weekly basis instead of the usual monthly basis. For further verification, customs officers could monitor the physical drawdown of oil stocks.

Financing and fees

Importers subject to stockholding obligations recover the costs of compulsory oil stocks by passing them on to consumers through market prices. The government of Luxembourg sets a maximum price on gasoline, automotive diesel, heating oil and liquefied petroleum gas (LPG). The pricing formula includes a fee to cover the cost of compulsory storage, amounting to EUR 5.95 per kilolitre (kl) for gasoline and EUR 6.45 per kl for distillates.

Other measures

Demand restraint

Current Luxembourg legislation allows for the regulation of oil product sales, purchases, transportation and consumption in times of supply disruption and empowers the Minister for Economic Affairs and Foreign Trade to decree the measures which can be applied to the general population or targeted to specific sectors or companies.

As the transport sector makes up the vast majority of oil consumption in Luxembourg, most demand restraint measures would be targeted at the use of transport fuels. Given the size and location of Luxembourg, such measures must take account of regional concerns.

Common Benelux guidelines exist for oil demand restraint which the Luxembourg government could rely upon for co-ordinating measures such as reducing speed limits or restricting driving. These common Benelux guidelines provide four levels of co-operation in an emergency situation implying demand restraint measures:

Information:

- information campaigns in order to promote reduced heating, illumination and car use
- speed limitation in residential areas and reinforced control and regulations.

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Consultation:

- decision to set standards for heating and illumination
- speed limitations on country roads.

Co-ordination:

- speed limitations on motorways
- driving bans
- limiting opening hours for filling stations
- limiting deliveries to consumers
- limiting deliveries to retailers
- introduction of tickets for consumers.

Uniformity:

- closing filling stations on determined days.

An information campaign could be started immediately after an ad hoc decision. Other light-handed measures, such as limiting speed on roads and reducing home heating, could be implemented within two days after consultation with other Benelux countries.

More severe measures, such as speed limitations on motorways, driving bans and reduced deliveries, would need to be co-ordinated at the Benelux level and eventually with other neighbouring countries. In this case, administrative preparations and decisions would take about one week. The timetable from implementation of decisions to full operation would be rather brief and the first volumetric effects would be measurable after two weeks.

Fuel switching

There is no scope for short-term switching away from oil use as an emergency response measure.

Other

With no domestic crude oil production, surge production is not an available response measure.

Gas

Market features and key issues

Gas production and reserves

Luxembourg has no indigenous gas production and therefore relies on imports to supply all its domestic requirements.

Gas demand

From 1990 to 2006, demand for natural gas increased from just less than 500 million cubic metres (mcm) to just over 1.4 billion cubic metres (bcm), an average annual increase of 6.8%. The 350 megawatt (MW) combined-cycle gas turbine (CCGT) plant in Twinerg consumes one-third of all natural gas in Luxembourg. Since the plant was commissioned in 2002, the transformation sector has accounted for some 40% to 45% of all gas used in

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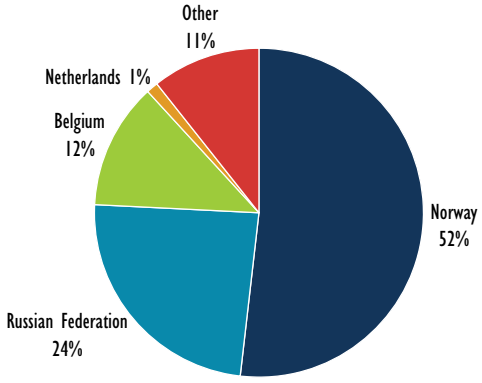
the country. Manufacturing represents around 35% and households 20%. Roughly half of all households are supplied with natural gas.

Natural gas is the principal source of fuel for the electricity generated in Luxembourg, providing over 90% of total inputs to electricity generation.

Gas import dependency

Norway is the main natural gas supplier, representing roughly half of all natural gas imports, while imports from the Russian Federation account for around a quarter of the total.

Figure 4.17.5 Natural gas imports by source, 2011

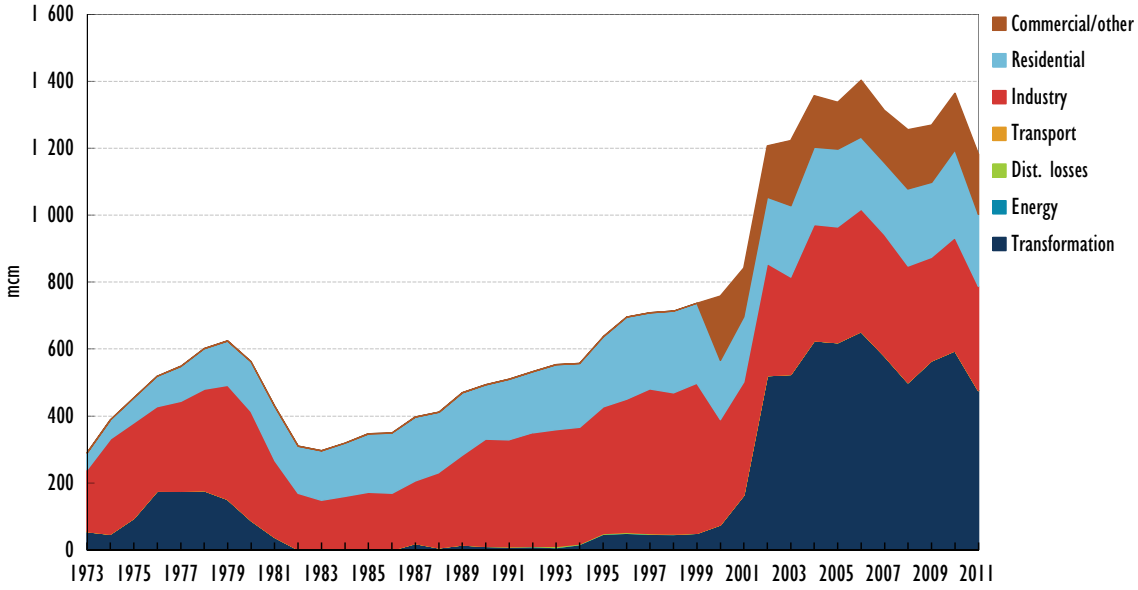


Gas company operations

Eight companies are authorised to supply natural gas to end customers in Luxembourg, including four integrated distribution system operators (DSOs).

The company SOTEG owns and operates the transmission system and supplies the majority of the market. It purchases most of its gas under long-term contracts, but also

Figure 4.17.6 Natural gas consumption by sector, 1973-2011



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buys on the spot market of the Zeebrugge hub in Belgium. At present, there is no real wholesale market for gas in Luxembourg, and SOTEG supplies all gas to the country's four DSOs. The transmission system operator (TSO) is owned by the state (21%), E.ON (20%), ArcelorMittal (20%), Cegedel (19%), Saar Ferngas (10%) and the state-owned SNCI fund (10%).

Since 2004, SOTEG is also involved in electricity. In a move to consolidate Luxembourg's energy sector, in 2009 SOTEG merged with Cegedel, the electricity incumbent, and the German gas supplier Saar Ferngas to form a new cross-regional energy player, Enovos International SA.

Gas supply infrastructure

Ports and pipelines

Luxembourg's natural gas pipeline network is not designed for transit for other countries; it does not have a compressor station and thus depends on the compressors of Belgium and Germany and has no substantial linepack. It consists of 380 km of transmission system network and some 2 300 km of distribution system network. The transmission network interfaces with four distribution systems and directly with some large industrial customers.

There are four entry points to the gas network with a total theoretical maximum capacity of 10.3 mcm per day; two from Belgium (Petange, with a maximum capacity of 3.8 mcm/d and Bras with 1.4 mcm/d), one from France (Audun with 0.5 mcm/d) and one from Germany (Remich with 4.6 mcm/d).

Storage

There is no natural gas storage in Luxembourg.

Emergency policy

The country's natural gas supply security measures are stipulated in guidelines for companies operating on its domestic gas market. These guidelines are required under the Law on the Organisation of the Natural Gas Market of 1 August 2007 and are also described in the emergency plan established according to the EU Regulation 994/2010 on the security of gas supply. The Ministry of Economic Affairs and Foreign Trade is responsible for monitoring the general state of the networks and interconnections as well as the security of supply.

Suppliers must guarantee supply to end-users in times of supply disruptions and under extreme weather conditions, including exceptionally high demand for gas during very cold periods (statistically recorded every 20 years). The law also obliges the system operators to invest in grids in order to ensure their security and safety, and to guarantee transport and distribution of gas in extreme weather conditions.

The law sets a public service obligation on gas suppliers, requiring them to contribute to the overall supply of the domestic market during a disruption. This also requires active co-operation with the other suppliers to maintain a steady supply to network operators. In this way, spare supply from the other suppliers may be utilised when any one of the four suppliers to the national market faces difficulties during defined periods of extreme circumstances.

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A load-shedding plan, developed by the TSO Creos in co-operation with distributors and other stakeholders, defines four categories of customers with different priorities of supply protection. Each category represents around 25% of total gas use.

The single largest gas user, the Twinerg CCGT plant, is not interruptible, although it accounts for one-third of the country's gas use. The plant is fully integrated into the Belgian power production park and the plant's capacity of 350 MW is divided between Belgium's Electrabel for the Belgian grid (150 MW), and Luxembourg's two electricity providers, Enovos and Sotel (100 MW each). Luxembourg contractually receives close to 40% of its electricity from the Twinerg CCGT plant. If the plant's natural gas supply is cut off, Electrabel is obliged to provide backup electricity.

As Luxembourg has no natural gas storage and no substantial linepack in its transmission grid, there is little supply flexibility within the country to compensate for lost gas supplies. With four entry points, the country could compensate for reduced flows through one of these by increasing supply through the others. However, with roughly half of the country's gas supplied through the German entry point, a significant reduction to capacity at this point would be difficult to compensate from the other directions.

Emergency response measures

There is no natural gas storage in Luxembourg and therefore no possibility for emergency release of natural gas.

Luxembourg has no demand restraint programme in order to rapidly reduce gas use in the short term during a gas supply disruption.

There is no policy to encourage users of natural gas to switch to other fuel sources in the event of a gas supply disruption.

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The Netherlands

Key data

Table 4.18.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	78.7	48.5	46.8	36.0	37.9	51.7	43.0
Demand (kb/d)	734.5	854.5	1 021.4	1 019.8	1 016.4	1 020.8	931.6
Motor gasoline	79.8	93.1	94.8	96.6	98.7	95.6	-
Gas/diesel oil	150.5	177.8	192.1	187.2	186.0	176.6	-
Residual fuel oil	182.1	208.8	275.5	227.7	244.1	219.1	-
Others	322.1	374.8	459.0	508.2	487.6	529.6	-
Net imports (kb/d)	655.8	806.0	974.6	983.8	978.5	969.1	888.6
Import dependency (%)	89.3	94.3	95.4	96.5	96.3	94.9	95
Refining capacity (kb/d)	1 381.0	1 187.8	1 227.5	1 236.4	1 236.4	1 236.4	-
Oil in TPES (%)**	36	36	39	38	38	39	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.18.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	76 249	72 821	78 510	88 510	80 570	80 143	67 487
Demand (mcm/y)	43 022	48 851	49 304	54 849	47 881	45 988	44 563
Transformation	9 925	14 410	16 104	18 660	16 648	0	-
Industry	12 274	12 557	11 453	10 534	10 014	0	-
Residential	10 978	11 119	10 496	12 057	9 809	0	-
Others	9 845	10 765	11 251	13 598	11 410	0	-
Net imports (mcm/y)	- 33 227	- 23 970	- 29 206	- 33 661	- 32 689	- 34 155	- 22 925
Import dependency (%)	- 77.2	- 49.1	- 59.2	- 61.4	- 68.3	- 74.3	- 51
Natural gas in TPES (%)	47	49	46	47	44	42	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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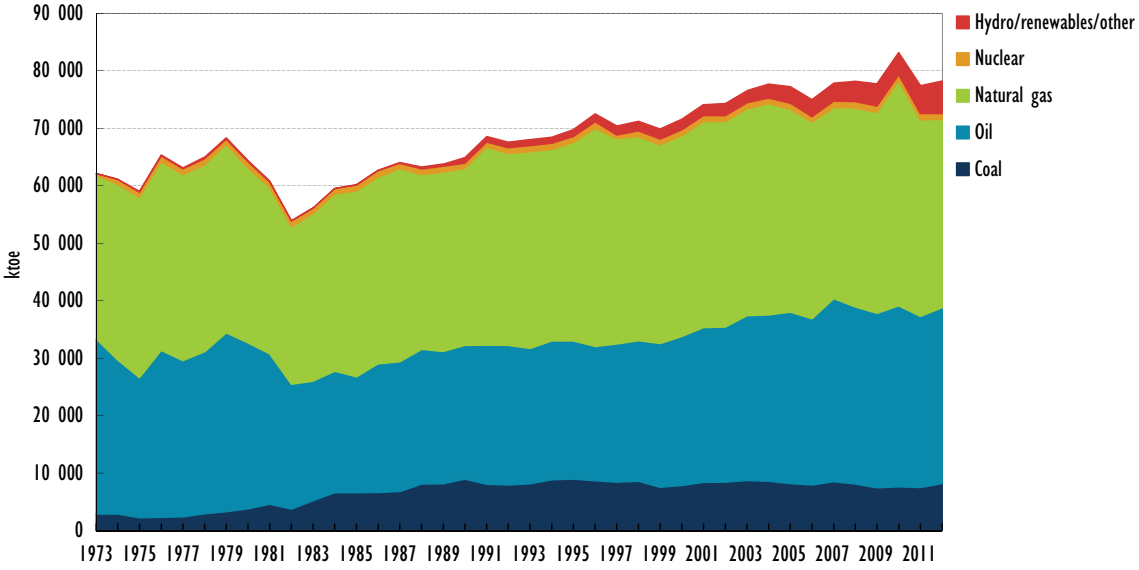
Figure 4.18.1 Total primary energy source (TPES) trend, 1973-2012



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Map 4.18.1 Oil infrastructure of the Netherlands

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Map 4.18.2 Gas infrastructure of the Netherlands

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Country overview

Oil and natural gas represented respectively 39% and 42% of the Netherlands's total primary energy supply (TPES) in 2012. While their share in the energy mix is expected to decline slightly over the next decade, demand for both fuels will rise as total energy demand in the country grows. The Netherlands plans to meet its future energy needs with an "all-in" approach, seeing a role for all fuels, including nuclear, and pursuing a goal of increasing renewable energy from the 4% it represented in 2010 to 14% by 2020. In terms of fossil fuels, new coal-fired power plants will come online in the coming years; natural gas will remain the country's key fuel, serving as the backup source for intermittent renewable power generation.

Oil demand in the Netherlands was roughly 1 million barrels per day (mb/d) in 2012, with an import dependency of roughly 95%. Domestic oil production is in decline in the Netherlands, and despite the extension of output made possible by new upstream techniques, the country will gradually move towards becoming fully import dependent in meeting its oil needs. At the same time, the Netherlands plays a key role as a major oil refining centre in Europe, with an extensive supply network of ports, storage facilities and pipeline connections playing a critical role for oil supplies to the continent. Likewise for natural gas, the country plays a regional role for supply security. However unlike for oil, the Netherlands produces more gas than it consumes domestically, making the country a net exporter. Substantial gas reserves remain and are expected to allow the Netherlands to continue as a net exporter of gas over the coming decade.

The emergency oil response system of the Netherlands is based on a mixed system of mandatory emergency reserve stocks held by both the industry and the Dutch stockholding agency, Centraal Orgaan Voorraadvorming Aardolieproducten (COVA). In times of an International Energy Agency (IEA) collective action, the most likely response by the Netherlands would be a drawdown of the public stocks held by COVA. The agency used to cover some 90% of the Netherland's total domestic stockholding obligation in the years up to 2012, however this share has decline to 75%, in conjunction with the transposition of the EU directive on emergency oil stockholding by the end of 2012.

The Dutch gas production and infrastructure capacities provide a significant level of security for domestic natural gas supply. However, as domestic production declines (the Netherlands is expected to become a net importer of gas sometime in the period between 2020 and 2025), well-timed investments in storage capacities and LNG installations will be necessary to maintain supply flexibility. The transmission system operator (TSO), Gasunie Transport Services (GTS), along with the distribution system operators (DSOs), must report every two years detailing capacity needs and planned investments in network capacity to ensure security of supply. GTS is also responsible for carrying out emergency measures in a gas crisis, and would be responsible for assuring gas supply to priority customers (households and small businesses) in conditions of extreme cold.

Oil

Market features and key issues

Domestic oil production

Domestic oil production began in the Netherlands following the discovery of oil deposits near Schoonebeek in 1943. Production from other onshore fields in the area of Rotterdam

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as well as from the Dutch sector of the North Sea beginning in 1982, contributed to total production reaching a peak of 90 thousand barrels per day (kb/d) in 1986. In 2012, total indigenous oil production in the Netherlands, including crude oil and natural gas liquids averaged 51.7 kb/d.

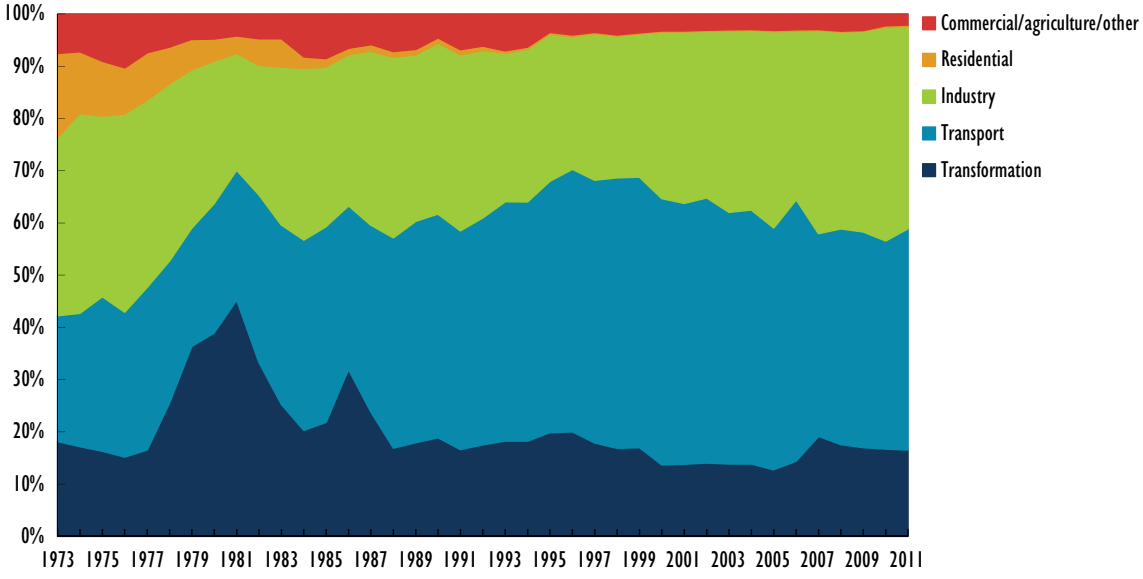
Production at Schoonebeek stopped in 1996, having produced only a quarter of the field's estimated reserves, as the crude stream was considered too viscous for production to be economically viable. Enhanced oil recovery techniques such as steam injection and horizontal drilling have reversed this, and in January 2011 the field was officially reopened for production. Production from the field is expected to average some 14 kb/d over the coming 25 years, with all amounts to be exported by rail to the refinery in Lingen, Germany.

Oil production from fields other than Schoonebeek, both onshore and offshore, is projected to continue to decline. Total indigenous production in the Netherlands is forecast to rise to just over 35 kb/d in 2015 and then decline steadily thereafter. Beyond 2035, only a small amount of natural gas liquids (NGLs) production is expected to continue. Import dependency, which stood at 95% in 2012, will therefore decline slightly in the period to 2015. Following this period, the Netherlands will gradually move towards becoming fully dependent on oil imports to meet domestic demand.

Oil demand

Oil product demand in the Netherlands averaged just over 1 mb/d in 2012. Total oil use has grown at an annual average rate of 1.5% since 2000. The industry and transformation sectors, which account for over 80% of all oil used in the Netherlands, have been the primary sectors leading oil demand growth. Oil consumption in these sectors has grown by an average of over 5% per year since 2000. Rising oil use has been primarily in the form of naphtha used by the petrochemical industry in these sectors. Demand for naphtha grew at an annual average rate of 9.5% from 2000 to 2012. Over the same period, demand for diesel grew by an average of 1.8% per year. Residual fuel oil was the second largest component of the oil products going to the Dutch market, however the vast majority of this, 98%, goes to international marine bunkers, fuelling international seagoing ships.

Figure 4.18.2 Oil consumption by sector, 1973-2011



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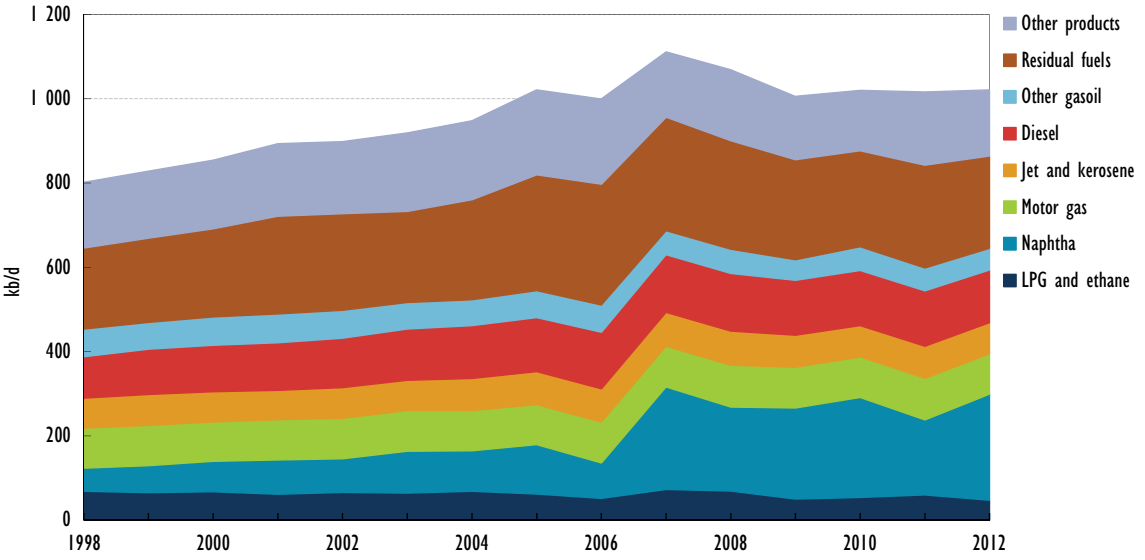
Total oil demand is expected to continue to grow in the coming years at an annual average rate of just under 1%. This rate would infer oil demand reaching 1.1 mb/d by 2020. The industry sector, which accounted for some 40% of oil demand in 2011 and which includes the petrochemical industry, will continue to be the driving force behind oil demand growth. The transport sector, which accounted for 42% of 2011 demand, is expected to decline owing to improved fuel economies and alternative fuel uses such as electricity and biofuels.

Figure 4.18.3 Oil demand by product, 1998-2012



Imports/exports and import dependency

With total refinery output in the country (1.25 mb/d) greater than domestic demand, the Netherlands is a net exporter of refined products. At the same time, large volumes of crude and oil products enter the country, only to be exported to neighbouring countries as regional suppliers take advantage of available port and storage infrastructure. Thus the Netherlands is a key link in European oil supply flows, with the total volumes of oil transiting over four times larger than Dutch oil demand.

In 2012, total imports (not including transit volumes) of crude oil and NGLs were nearly 60 million tonnes (Mt), or an average of 1.27 mb/d. Roughly one-quarter of these imports were from the North Sea, a third from the Russian Federation and another third from OPEC member countries.

Total output of finished products from domestic refining was 57.4 Mt, or an average of 1.23 mb/d in 2012. The Netherlands also imported 1.9 mb/d of oil products in 2012, compared to just over 2 mb/d of product exports. Net exports of gasoline were primarily to North America while net exports of middle distillates were primarily to Germany, Belgium and France. At the same time, the Netherlands is a net importer of fuel oil, naphtha and "other products" for the petrochemical sector (207 kb/d in 2012), mostly from Russia.

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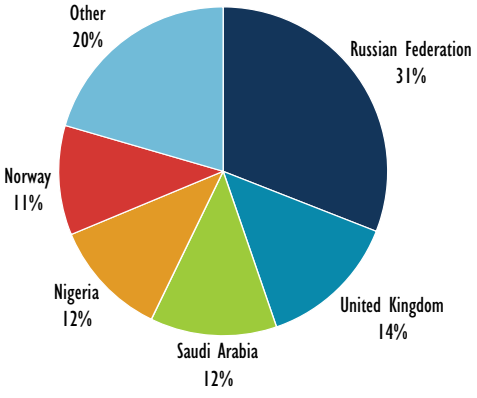
Figure 4.18.4 Crude oil imports by origin, 2012



Oil company operations

Dana Petroleum and NAM (jointly owned by Shell and ExxonMobil) are the country's main domestic crude oil producers. NAM is also the country's largest natural gas producer.

Five companies operate refineries in the country, with Shell and BP operating the two largest (Pernis and Europoort, respectively), while ExxonMobil and Kuwait Petroleum (KPC) also operate refineries located in the Rotterdam area. Total and Lukoil jointly operate the Zeeland Refinery in Vlissingen.

The Netherlands Petroleum Industry Association (VNPI) represents the ten main companies operating on the Dutch upstream, retail and wholesale oil market. These companies collectively represent 99% of production and 80% of oil products sold on the Dutch market.

VOTOB is an association representing 14 independent tank storage operators in the Netherlands, defined as companies providing logistic services to customers without having ownership of the products in custody. These companies temporarily store liquid products for customers, with tanks ranging in size from 100 to 100 000 m³.

Another industry association on the Dutch oil sector is *Nederlandse Organisatie Voor de Energiebranche* (NOVE), which represents independent companies trading, selling, transporting and storing liquid fuels and lubricants on land and water. NOVE has 185 members representing 75% of independent fuel traded by volume.

Oil supply infrastructure

Refining

The Netherlands' five refineries have a total crude distillation capacity of roughly 1.2 mb/d. One of the refineries (Total/Lukoil) is located in Vlissingen; the other four (ExxonMobil, KPC, BP, and Shell) are in the Rotterdam area.

In 2012, the country's refined product output totalled 1.2 mb/d and the capacity utilisation rate of Dutch refineries was almost 100%. The composition of production was gas/diesel oil (34%), motor gasoline (13%), residual fuel oil (13%) and naphtha (15%). The remaining capacity was used for LPG and ethane production (4%) and other products (8%). The Dutch refineries have a significant surplus in production of diesel, by a margin of nearly 240 kb/d over local demand (demand stood at 177 kb/d, while 415 kb/d of diesel were produced in 2012).

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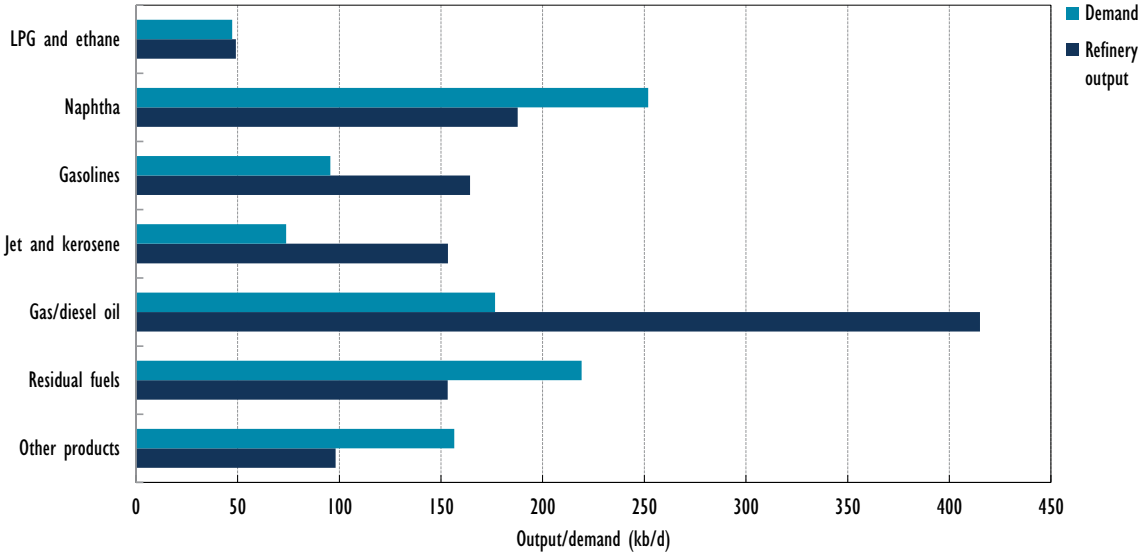
The Dutch refinery industry is primarily focused on exports, with most of its product output (63%) directly exported. Furthermore, another 12% of output from the refineries is exported by the petrochemical industry.

Figure 4.18.5 Refinery output vs. demand, 2012



Ports and pipelines

Dutch ports are of international importance and the country is the largest hub in Europe for inland waterway bunkering.

The Rotterdam area is well connected with the hinterland, both by river and by pipeline. It is the world's third largest marine bunker harbour, after Singapore and Shanghai. The Rotterdam harbour is eager to develop itself as an energy harbour for the future, and is oriented towards developing biobased industries and biofuel production and stockholding plants.

The Zeeland Refinery is located in Vlissingen port which is situated between the ports of Antwerp and Rotterdam; it is therefore of strategic importance to balance supply to both demand centres.

The Amsterdam port is especially oriented towards oil products and has developed into one of the most important gasoline stockholding sites in the world.

The Delfzijl/Eemshaven port area is undergoing extensive development with new tank capacity for strategic stockholding and for biofuels.

There are two major crude oil pipelines in the Netherlands: the Rotterdam-Rhine Pipeline (RRP) to Germany's Ruhr region has a capacity of 400 kb/d; the Rotterdam-Antwerp Pipeline (RAP) pipeline to Belgium's Antwerp area has a capacity of 600 kb/d.

Rhine-Main Pipeline (MMP, also referred to as the RMR) is a major product pipeline to Germany, with a capacity of 250 kb/d. In the Rotterdam area and the southwest of the country a huge grid of pipelines connects the terminals, depots and the refineries, including the Zeeland Refinery.

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Storage capacity

Total storage capacity in the Netherlands is estimated at some 189 mb (30 mcm). Most of this storage is in the Rotterdam area, but Amsterdam and Vlissingen also have abundant storage capacity. In addition to the large terminals of the oil companies, several independent tank storage companies have large stockholding capacities in the Netherlands. The largest is the Maasvlakte Olie Terminal (MOT) near Rotterdam. A joint venture of BP, ExxonMobil, Kuwait Petroleum, Shell, Total and Vopak, the MOT is one of the world's largest oil terminals comprising crude oil in 39 tanks with a total capacity of 28 mb (4.4 mcm).

In the east of the Netherlands, near Hengelo, there are plans for creating three salt caverns for holding up to a total of 2.8 mb of diesel. Each cavern would be 150 000 m^3 at a depth of 450 metres. The final licence approvals are still pending.

Because of the relatively large storage capacity in the Netherlands, as well as the relatively large number of bilateral agreements that the administration has concluded, Dutch companies are very active in regional stockholding arrangements.

Decision-making structure

The Minister of Economic Affairs of the Netherlands (MEAN) is responsible for oil and natural gas emergency policy, with flexibility as a vital component. In most crisis situations, the Dutch administration believes that regular market forces should adequately allocate oil instead of activating any sharing system.

The precise mix of emergency measures to be used in the Netherlands in a crisis would be determined according to the nature and expected duration of the crisis and the needs of the markets. However, Dutch oil emergency policy points towards a strong preference for stockdraw in most emergency situations.

The Dutch national emergency strategy organisation (NESO) prepares and advises the Minister of Economic Affairs, Agriculture and Innovation and the Cabinet on matters of oil emergency measures and their implementation. In normal times, the NESO is made up of officials from the Energy Markets Directorate in the Directorate-General for Energy, Telecom and Competition. In emergency situations (as well as for test purposes), the basic NESO organisation is enlarged to include officials from other relevant departments. Contact between the NESO and industry is co-ordinated through the oil industry advisory group. The NESO would also be in contact with other departments, international organisations and the Dutch stockpiling agency COVA.

During a crisis, the NESO would convene a number of "measure groups" to prepare and execute specific measures. These groups would be staffed by representatives from the various ministries and from the oil industry. Industry would be consulted and would have a role in the preparation and implementation of specific measures (e.g. stockdraw and refinery measures), however it would not participate in decision-making within the governmental structure.

Stocks

Stockholding structure

The Netherlands has a mixed system, in which both industry and the government agency COVA are required to hold emergency stocks. Because of their international activities, refining and supplying companies tend to hold unusually high volumes of stocks as part

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of normal operations. In effect, the Netherlands is always holding well in excess of its obligations under both EU and IEA requirements.

Crude or products

The industry can fulfil its stockholding obligations with either crude oil or products.

To cover its stockholding obligation, COVA entered into ticket contracts with the domestic oil industry for 0.71 Mt of oil products. The remaining stock obligation of COVA (3.8 Mt) consists of crude oil, gas oil and motor gasoline which is fully owned by COVA and pledged to the state of the Netherlands. COVA holds just over half of its overall stock obligation as crude oil.

Location and availability

Because of the high cost of storage in the Rotterdam area, around one-third or some 13 mb (1.8 Mt) of COVA crude oil stocks are held in salt caverns near Wilhelmshaven (Germany). The remaining quantities of crude are held in above-ground storage in the Netherlands.

Company stock obligations are held as part of normal operating inventories.

Many traders on the Dutch market have little or no inventory levels, instead operating just-in-time deliveries from refineries or depots directly to customers by truck. In such instances, companies are able to fulfil their stockholding obligation with stockholding ticket contracts. Emergency stocks may also be held abroad, without restriction as to the portion of the obligation, as long as bilateral agreements are in place. The Netherlands has bilateral agreements with 11 countries.

Monitoring and non-compliance

Companies with stockholding obligations (including both national obligations and reserved stock obligations by tickets) are required to submit monthly reports on their relevant stock levels to the MEAN. The reports are checked by the ministry, which may delegate the Tax Inspection Service of the Ministry of Finance to conduct audits of the records and on-site physical checks. Any suspected infringement is reported to the Fiscal Intelligence and Investigation Service and the Economic Investigation Service (FIOD/ECD) of the Ministry of Finance for further investigation.

Stock drawdown and timeframe

In an oil crisis, all compulsory stocks are at the disposal of the minister of MEAN, who has the authority to invoke a variety of statutes, depending on the situation. In principle, a decision to authorise a stockdraw could be taken within 24 hours.

In most situations, a stockdraw would first focus on making COVA stocks available through a tendering mechanism. It would be carried out in full co-operation and consultation with international bodies and other countries.

Once their obligation to hold stocks has been lowered, companies with a stockholding obligation are expected to co-operate through voluntary drawdown of their stocks. An order to companies to draw down their inventories would only be considered in a very severe crisis.

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Financing and fees

The operational costs and financial expenses of COVA are covered by a stockholding levy which has been defined at EUR 8.00 per m³ in the 2012 Oil Stockpiling Act and can be amended by an Order of Council.

Other measures

Demand restraint

The Dutch demand restraint programme focuses first on voluntary measures. If these prove to be inadequate, Dutch authorities can proceed to obligatory measures. The NESO would aim to reduce the private and recreational use of petroleum products, while leaving basic economic activities untouched as much as possible.

Decisions to implement demand restraint measures would be taken by the MEAN, or by the Cabinet, based on a proposal by this minister. The minister would be advised by the NESO operational team (within the ministry) and by an interdepartmental policy team for the Cabinet. On average the preparation of a Cabinet decision may take two to three weeks, or shorter if urgency so requires. However, after such a decision is made, there are lead times for implementation. In practice, however, both periods may partly run parallel. Time is necessary for preparing all issues related to the implementation, such as communications, control systems, instructions to relevant parties, etc. The necessary timing will differ according to measure.

The NESO has prepared the following set of demand restraint measures, which could be implemented on short notice:

- communication to the public, including a call for voluntary reduction of oil consumption
- reduction of speed limits
- Sunday driving bans (allied with bans on pleasure boating and flights)
- supply of priority end-users and critical infrastructure sectors
- request for appropriate refinery action and
- bans on filling containers to limit hoarding.

Fuel switching

Oil use in the Netherlands is heavily concentrated in sectors which do not provide opportunities for short-term switching, such as transportation and industry (petrochemical) sectors.

Other

Short-term surge production capacity in the Netherlands is considered inconsequential.

Gas

Market features and key issues

Gas production and reserves

The Netherlands became a significant producer and exporter of natural gas following the discovery in 1959 of a gas field near the village of Slochteren in the northern province of Groningen. Offshore production in the Dutch sector of the North Sea began

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in the 1970s. By the end of 2010, the Netherlands had produced a cumulative total of nearly 3.2 trillion cubic metres (tcm) of natural gas, while remaining gas resources were estimated at 1.3 tcm. Of these remaining resources, the Groningen field accounted for 980 billion cubic metres (bcm), with 160 bcm to be found in other smaller onshore fields and 164 bcm in offshore formations.

The Netherlands produces two types of natural gas, one with a low-range calorific value below 10.5 kWh/m³ (L-gas), mainly from Groningen, and one with a high calorific value from 10.5 to 12.8 kWh/m³ (H-gas), from smaller fields. H-gas and L-gas must be transported on separate networks.

In 2011 the total production of natural gas in the Netherlands was over 80 bcm. The Groningen field is by far the largest source of Dutch gas production, and accounted for some 54 bcm of the 2011 total. The natural geology of the field allows for a great amount of flexibility in adjusting the field's output flow in order to respond immediately to actual demand from end-users. This allows the field to play the role of swing producer in order to meet seasonal fluctuations in demand.

Indigenous gas production in the Netherlands is expected to continually decline over the coming decades. Future production levels are linked to a Dutch gas policy provision, which sets a maximum allowance for Groningen total output to ensure that the Groningen field can continue to fulfil its function as a swing producer for the longest time possible. For the period from 2011 to 2020, this cap is set at to 424.7 bcm Groningen-equivalent gas (Geq). This implies an annual production of 44.6 bcm (Geq), however the flexibility role of the Groningen field necessarily implies some uncertainty as to its annual output over this period.

Based on the Dutch government's outlook for indigenous production and domestic use of natural gas, the Netherlands is expected to shift from being a net exporter to being a net importer of gas in the period between 2020 and 2025.

Gas demand

Domestic gas consumption in the Netherlands totalled some 48 bcm in 2011. Over one-third of total gas was consumed by the transformation sector. With some 96% of all households connected to gas supplies, the residential sector accounted for a substantial share, at 22% of the total, while the commercial and industry sectors each accounted for another 20% of gas use.

Natural gas demand is projected to grow steadily over the coming two decades. Growth in demand will be driven primarily by the use of gas for electricity generation and to a lesser extent by the industry sector. Demand in the residential and commercial sectors is expected to decline slightly owing to greater energy efficiency measures such as better insulation.

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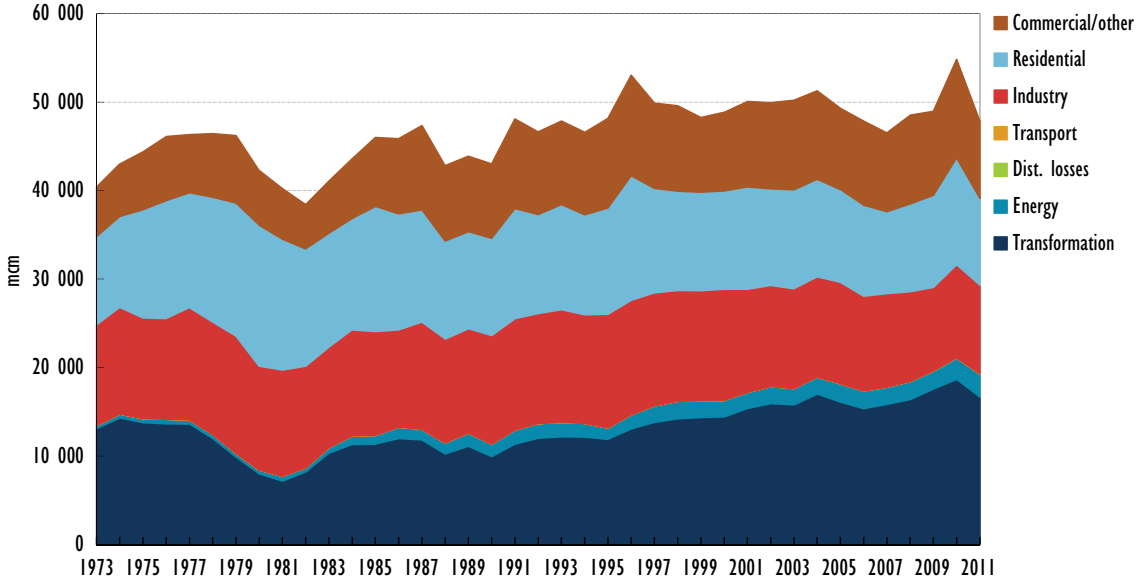
Figure 4.18.6 Natural gas consumption by sector, 1973-2011

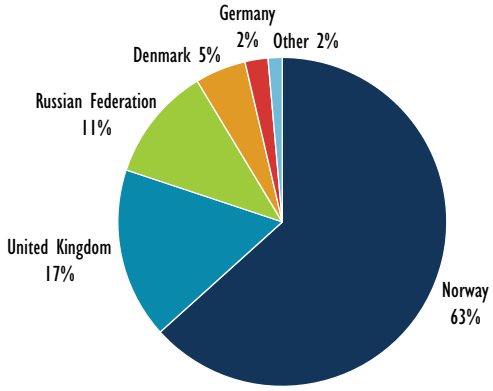


Gas import dependency

The Netherlands is the largest gas producer within the European Union. At the same time, the Netherlands imports and exports large volumes of gas, with roughly 40% of the total volume of gas used domestically.

In 2011, the Netherlands exported 55.8 bcm of natural gas. The largest portion of these exports, 21.8 bcm, went to Germany while Belgium was the destination of some 10 bcm and Italy of 8.7 bcm. Substantial volumes were also exported to France (7.4 bcm) and the United Kingdom (6.7 bcm). In the same year, the Netherlands imported nearly 26 bcm of gas, primarily from Norway, the United Kingdom and Russia.

Figure 4.18.7 Natural gas imports by source, 2011



Gas supply infrastructure

Ports and pipelines

Gasunie Transport Services B.V. (GTS) has been the operator of the national transmission system since July 2004. GTS is responsible for all national transport infrastructure

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operation and development. The Dutch gas network comprises 12 050 km of pipelines, 50 entry points (mainly from Dutch gas fields), 1 100 delivery stations and 25 interconnection points.

The Dutch network consists of separate networks in order to accommodate the transportation of the two different qualities of gas, H-gas and L-gas. Nearly all residential and commercial consumers use (blended) L-gas, while industry and power generators use mostly H-gas. Some L-gas used by final consumers comes from H-gas, having been converted to L-gas in blending stations. L-gas is also exported through dedicated transmission pipelines to customers in Belgium, France and Germany.

The Dutch transport network is directly connected to four European countries via 25 interconnections. Gas can be both exported and imported via connections with Belgium and Germany. However, gas can only be exported via the connection with the United Kingdom (the Balgzand Bacton Line) and gas can only be imported via the connection with Norway.

Storage

At the end of 2011 there were four underground natural gas storage facilities in the Netherlands with a total capacity of 5.2 bcm of working gas. Additionally, there are ten caverns in Epe, Germany, connected to the Dutch transmission system, providing a further 1.5 bcm of working capacity.

The role of storage capacity will become increasingly important in maintaining supply flexibility as domestic production declines. As noted above, gas production from the Groningen field plays an important role in accommodating seasonal fluctuations in market demand. As production from the field declines, so too will this flexibility. Storage which can accommodate summer/winter variations, such as from converted depleted gas fields, will be increasingly important to compensate for this decrease in production flexibility. Future storage capacity needs will also be augmented by the growing role of natural gas-fired power plants to back up electricity generation from intermittent renewable sources such as solar and wind.

Emergency policy

In the case of a natural gas crisis, measure have been put in place to protect households and other small consumers, while the Netherlands seeks to assure security of gas supplies by establishing itself as a gas junction in the international transport of gas and as a distribution centre for northwestern Europe.

The 2004 Gas Act establishes responsibilities related to gas crises with the (MEAN). As provided for under the act, the minister appoints GTS, as the national gas TSO, to perform certain tasks specified in the act; however the ultimate responsibility remains with the minister. Tasks allotted to GTS include performing the specific tasks established in related EU regulations, such as developing and updating a risk assessment every two years, and creating a preventive action plan and emergency plan. Emergency supply procedures are activated if a licence-holder/supplier cannot supply gas to small consumers (residential customers and small and medium-sized enterprises, defined as customers with a connection transit flow of 40 m^3 or less per hour). In such situations, GTS has measures to guarantee temporary supply to these consumers as long as they have failed to find an alternative supplier.

Retail suppliers of small consumers in the Netherlands are responsible for acquiring both the capacity and volumes necessary to supply their customers. GTS is statutorily responsible for the reservation of the necessary additional volumes and capacities

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to meet the increased demand of domestic consumers whenever the effective daily temperature falls to between -9°C and -17°C.

Peak supply standard

The European standard of 1 in 20 years established in its 2010 regulation can be translated for the Netherlands into a temperature of -15.5°C. The existing Dutch standard for infrastructure and security of supply under peak circumstances is more strict, as it is related to a situation occurring when there is an average daily temperature of -17°C, corresponding to a probability of once every 50 years. This supply standard is established under the "Decision on Security of Supply Gas Act".

The act also contains general clauses in case a supplier does not meet its obligations. In such cases, GTS has a co-ordinating task to make sure that the customers of the non-compliant supplier continue to receive supply. Non-compliance of a supplier does not imply shortage of gas, and therefore can be solved by the market. In this way these customers can choose a new supplier within a reasonable time without an interruption in their gas supply.

At the end of 2011 (2011-12 season) a total capacity of 2.44 mcm/h and a volume of 101 mcm was contracted for the peak supply of gas. This provides an operating time of 41.4 hours at maximum capacity. However, only part of the total consumption is supplied via peak supply (i.e. the additional maximum hourly capacity necessary when the effective daily temperature is -9°C or lower). Depending on how the temperature actually progresses during the course of a day, gas will only be supplied from peak supply for part of the day, notably during the morning peak and the evening peak. Thus the maximum contracted capacity will only be necessary for a limited number of hours in the event of an effective daily temperature of -17 °C. Hence, in practice, it will be possible to ensure peak supply for several days.

GTS uses two facilities to guarantee the production capacity required for peak supply: Gasunie's LNG installation on the Maasvlakte (the LNG peak shaver), and external capacity purchased on the market by means of an annual tender. The peak shaver is partly allocated for peak supply use as described in the Decree on Gas Security of Supply. GTS uses the other part of this installation for transport support. Hence it may be the case that this installation is in fact being used even though the limit under which peak supply takes place, -9°C, has not yet been reached.

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New Zealand

Key data

Table 4.19.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	58.1	44.6	24.2	59.8	50.2	45.7	17.7
Demand (kb/d)	106.7	133.8	152.8	151.7	150.9	151.0	158.9
Motor gasoline	45.3	50.3	55.2	54.5	53.3	52.9	-
Gas/diesel oil	25.8	42.8	51.1	50.5	52.0	53.3	-
Residual fuel oil	4.6	4.9	6.3	5.9	5.6	5.8	-
Others	30.9	35.7	40.2	40.8	40.0	39.2	-
Net imports (kb/d)	48.6	89.2	128.6	91.9	100.7	105.3	141.2
Import dependency (%)	45.5	66.7	84.2	60.6	66.7	69.7	89
Refining capacity (kb/d)	95.0	98.0	103.6	134.0	134.0	134.0	-
Oil in TPES (%)**	28	33	36	33	33	33	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.19.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	4 910	6 324	4 129	4 832	4 360	4 590	4 372
Demand (mcm/y)	4 888	6 327	4 126	4 651	4 326	4 653	4 372
Transformation	2 526	2 374	2 206	2 210	1 891	0	-
Industry	1 938	3 346	1 254	1 785	1 785	0	-
Residential	95	195	181	161	154	0	-
Others	329	412	485	495	496	0	-
Net imports (mcm/y)	- 22	3	- 3	- 181	- 34	63	0
Import dependency (%)	- 0.5	0.0	- 0.1	- 3.9	- 0.8	1.4	0
Natural gas in TPES (%)	30	30	19	21	19	21	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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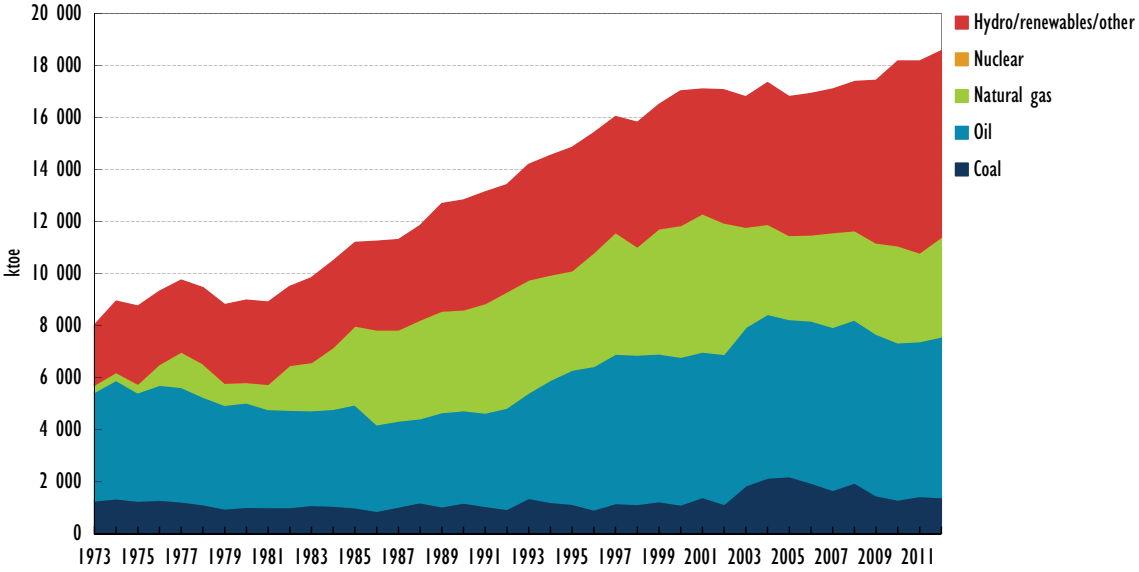
Figure 4.19.1 Total primary energy source (TPES) trend, 1973-2012



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Map 4.19.1 Oil infrastructure of New Zealand

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Map 4.19.2 Gas infrastructure of New Zealand

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Country overview

New Zealand's relative geographical isolation from the global oil and natural gas market supply chain creates a particular challenge to oil and natural gas supply security. Fortunately, New Zealand has relatively abundant domestic fossil fuel resources, compared to most International Energy Agency (IEA) member countries. It has large reserves of coal and some reserves of natural gas and oil.

Oil consumption has declined slightly since 2005, following a period of steady growth since the mid-1980s. Although there is some domestic production, imports are necessary to meet around 70% of New Zealand's oil demand. Most imports are in the form of crude oil. Following an upgrade, New Zealand's sole refinery supplies more than 80% of the country's product demand.

New Zealand's oil emergency response policy is based on an escalating series of measures ranging from the release of oil stock "tickets" to a range of demand restraint measures. During an IEA collective action the New Zealand government's preferred response would be the release of stock tickets, while demand restraint measures are only likely to be used as a last resort.

New Zealand places no minimum stockholding obligation on industry and, until 2007, the country relied on the industry's normal stockholding practices to meet the country's 90-day net-import obligation as a member of the IEA. Since 1 January 2007, the New Zealand government has routinely acquired ticket reservations for stocks held in other IEA countries to supplement the country's domestically held commercial stocks to ensure that it meets its 90-day obligation.

All tickets are held directly by the New Zealand government, rather than through an agency on the government's behalf. In an IEA co-ordinated action, New Zealand would likely contribute to the collective response by releasing these public stocks, and possibly implementing a campaign for voluntary demand restraint.

New Zealand has significant domestic natural gas production – enough to meet 100% of the country's natural gas demand. The country does not have a liquefied natural gas (LNG) import terminal, and will remain entirely reliant on domestic production for its gas needs for the foreseeable future.

New Zealand's natural gas demand has declined by some 33% since its peak in 2001, and stood at 4.65 billion cubic metres (bcm) in 2012. Demand is dominated by the energy and transformation sectors, which together accounted for 50% of total gas demand in 2011.

There are no government-mandated requirements on gas pipeline owners, system operators or industry participants to hold minimum reserves of natural gas. However, these participants, particularly the system operators, are required to maintain operating pressure in the reticulated network and therefore grid owners, system operators or industry participants will hold a certain amount of "reserve gas" as linepack for this purpose.

The Ahuroa Gas Storage (AGS) facility, New Zealand's first underground natural gas storage facility, was officially opened by Contact Energy, one of New Zealand's electricity and gas power companies, in May 2011. It is primarily intended to provide gas supply flexibility for the purposes of managing periods of peak demand, so does not constitute a strategic gas reserve.

Curtailment of gas demand is the primary tool in managing significant gas supply emergencies.

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Oil

Market features and key issues

Domestic oil production

All New Zealand's oil production is from fields in the Taranaki Basin, located on the west coast of the North Island. Most of the basin is located offshore, but the majority of small producing fields are onshore. Most oil produced in New Zealand is light, sweet crude. However, New Zealand's sole refinery is geared towards sour crude, so the majority of oil produced in the country is exported.

Following a surge in production brought on by the streaming of the Tui field in 2007 and the commissioning of the Maari field in 2009, New Zealand's average rate of oil production has declined recently. However, some fields are expected to show an increase in production in 2014.

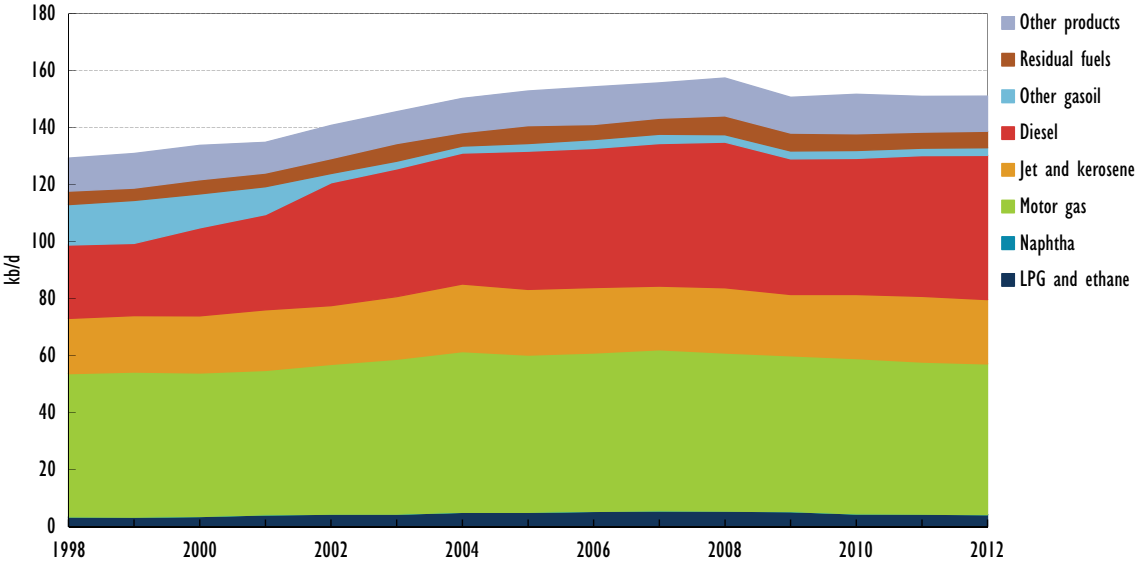
The country's oil production, including natural gas liquids (NGL) averaged 45.7 thousand barrels per day (kb/d) in 2012, down from 50.2 kb/d in 2011 and a peak of 59.8 kb/d in 2010. According to IEA forecasts, New Zealand's rate of production is expected to enter a long-term phase of decline in the absence of new discoveries.

Oil and natural gas exploration activity has increased in recent years and is continuing to increase. The main focus remains on the Taranaki Basin, but there has also been activity in other areas, including the east coast of the North Island, off the east coast of the South Island, and in the lower South Island.

Oil demand

New Zealand's oil demand has declined slightly since 2005, following a period of steady growth from the mid-1980s. Total oil demand averaged 151 kb/d in 2012, accounting for 33% of the country's total primary energy supply (TPES). As in many OECD member countries, the transportation sector accounts for an increasing share of total oil demand, reaching 77% in 2011.

Figure 4.19.2 Oil demand by product, 1998-2012



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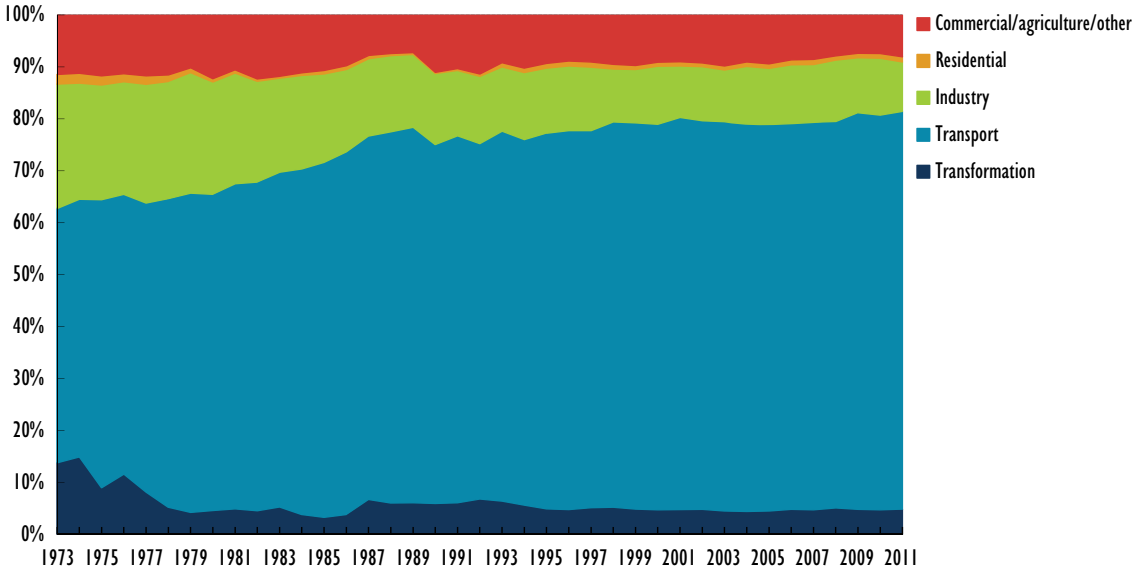
Motor gasoline, gas/diesel oil, and jet kerosene are the main transportation fuels. Demand for diesel oil has grown at a notably rapid pace over the past decade. Diesel consumption averaged 51 kb/d in 2012 (accounting for 33% of total oil demand), up from 45 kb/d in 2003 – an increase of nearly 13%. In contrast, gasoline is still marginally ahead of diesel consumption – averaging 53 kb/d in 2012 (35% of total oil demand) – but is down 1.9% from 54 kb/d in 2003.

Figure 4.19.3 Oil consumption by sector, 1973-2011



According to IEA forecasts, oil demand is expected to increase in the medium term, reaching 159 kb/d by 2018. Future oil demand growth in New Zealand will primarily be driven by increases in the use of transport fuels.

Imports/exports and import dependency

New Zealand's relative geographical isolation at the end of the global oil market supply chain creates a particular challenge to oil supply security. For example, the long maritime shipping routes for oil and product imports means that if the country suffered a major oil or oil product supply disruption it could take weeks to take delivery of alternative supplies.

On average, oil consumption has grown steadily since the mid-1980s, and although there is some domestic production, imports have historically been necessary to meet the majority of New Zealand's oil demand. In 2012 New Zealand imported almost 70% of its (net) oil requirements, up sharply from 60.6% in 2010. If this trend continues import dependence is forecast to reach 89% in 2018.

Around two-thirds of oil imports are in the form of crude oil. New Zealand's import sources are well diversified, coming primarily from Brunei, Saudi Arabia and other Near and Middle Eastern countries, and to a lesser extent from Southeast Asian countries, including Malaysia and Indonesia, as well as Australia.

Only one-third of New Zealand's imports are in the form of products. In 2012 these came primarily from Singapore (61%) and Korea (27%), according to IEA figures.

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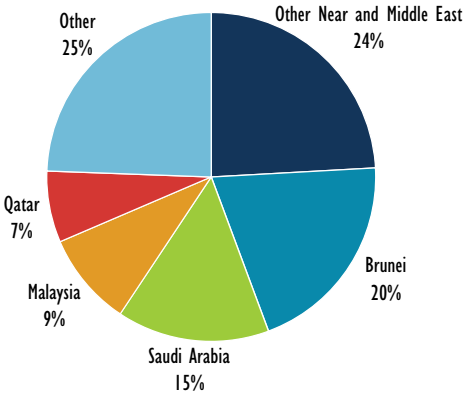
Figure 4.19.4 Crude oil imports by origin, 2012



New Zealand's sole refinery, Refining NZ, supplies more than 80% of the country's product demand. The country's remaining product requirements are imported. As demand for these products (particularly road transport fuels) continues to rise, product imports are likely to rise further.

Oil company operations

At the wholesale level, New Zealand is a highly concentrated market, with the four main oil companies – BP, Chevron (Caltex), ExxonMobil and Z Energy – maintaining an all-products market share of up to 95%. At the retail level, there is more competition than at the wholesale level, with at least 15 branded networks and a rising number of unbranded sites. Collectively, these smaller networks account for over 15% of the retail market. Gull is the biggest independent retailer, with a market share of 2% to 3%, but the company has found its retail scope geographically limited to the northern half of the North Island because its only storage terminal is located in Mount Maunganui.

Oil supply infrastructure

Refining

As previously mentioned, New Zealand has one refinery, Refining NZ, at Marsden Point, near Whangarei in the North Island. In late 2009, the refinery's topping capacity was increased from 104 kb/d to approximately 120 kb/d. Refining NZ supplies more than 80% of the country's refined product demand.

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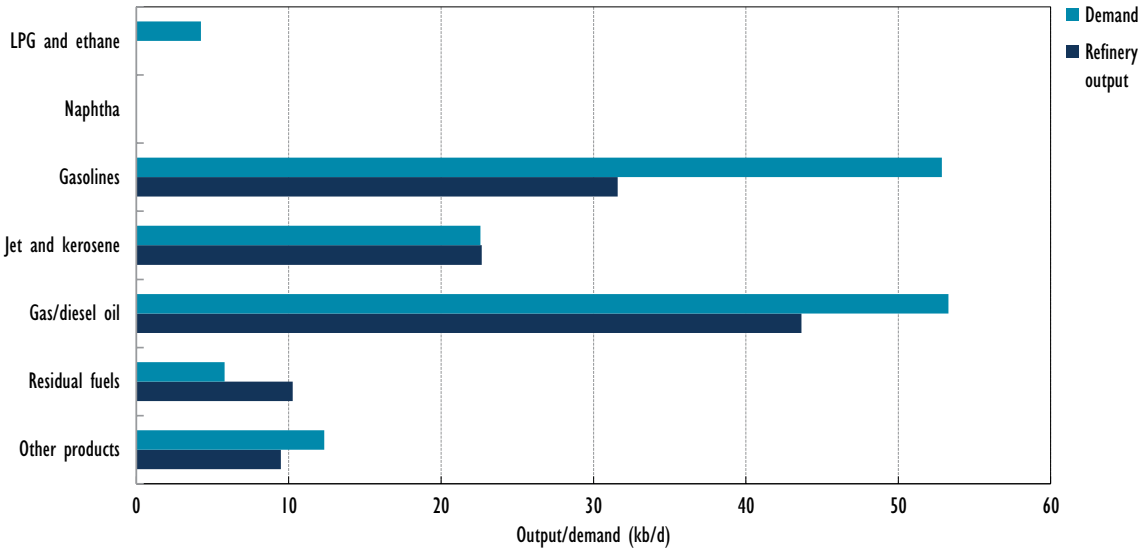
Figure 4.19.5 Refinery output vs. demand, 2012



Refining NZ is a toll refiner, i.e. it charges a fee to convert crude oil and other feedstock into refined products. This fee is based on the difference between the value of initial feedstocks and final products, according to reported Singapore prices. Refining NZ's profits are not affected by downstream pricing decisions of the four oil companies (BP, Chevron, ExxonMobil and Z Energy) that own the majority of the refinery. Importantly, the four oil companies have processing agreements which allocate the full capacity to them, unless they choose not to use it.

Ports and pipelines

Refining NZ owns the Refinery to Auckland Pipeline (RAP), which transports refined products to bulk storage facilities in the greater Auckland area, New Zealand's major petroleum market. The pipeline has a capacity of some 53 kb/d (2.6 Mt/yr); as of early 2010 about 90% of this capacity was utilised. About half of the refinery's production is distributed via the RAP pipeline; the balance is transported by coastal tankers and by road to the rest of New Zealand.

Coastal distribution delivers refined product from Refining NZ to a number of locations around New Zealand, where industry receives finished products (from Refining NZ via coastal distribution as well as imports). New Zealand has 13 terminal locations (including the refinery), of which 11 are seaboard terminals. The Marsden Point truck-loading facility serves the Northland and North Auckland region, while the Wiri (South Auckland) terminal supplies Auckland (and parts of Waikato), and receives product from Refining NZ via the RAP. The three major import terminals are Mount Maunganui, Wellington and Lyttelton.

Storage capacity

New Zealand does not hold public stocks domestically, nor does it impose an obligation on industry to hold stocks. As such, all storage capacity is commercially built and used. Because of the country's geography, ports and storage are closely intertwined, as products are primarily transported around the country by ships.

The oil majors employ a system that enables each company to draw product from any location subject to having access arrangements with a specific storage provider. This

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system is designed to offer a great deal of flexibility and efficiency to the domestic supply chain. The system works on an accounting system in which stock volumes are credited to companies based on a combination of refinery production as it accrues to the individual company processing at Refining NZ and as supplemented by periodic imports. A company's ability to draw stock from the system is subject to having a positive stock balance.

Decision-making structure

The Ministry of Business, Innovation and Employment (MBIE) is responsible for policy related to oil supply security and in an international disruption would chair the national emergency strategy organisation (NESO) and take the lead in developing a plan of action. However, the Ministry of Civil Defence and Emergency Management (MCDEM) is responsible for civil contingency planning through a national Civil Defence Emergency Management (CDEM) Plan and for liaison with local authorities for domestic events at the local and regional level.

MCDEM's mandate covers aspects such as pandemics and natural disasters (e.g. earthquakes), and is leading work to improve domestic contingency planning within the petroleum sector. MBIE is working with MCDEM to ensure co-ordination between operational responsibilities.

New Zealand's NESO is made up of staff from MBIE, as well as representatives from oil companies and from Refining NZ. In an oil supply emergency, depending on the nature and scale of the disruption, the NESO would invite relevant non-members to participate in consultations, including representatives of large user groups such as the Road Transport Forum and the Automobile Association.

There are two main legal instruments available to authorities during an oil supply disruption: the International Energy Agreement Act of 1976 (IEA Act) and the Petroleum Demand Restraint (PDR) Act of 1981. The IEA Act enables New Zealand to carry out its obligations as a member of the IEA, including compliance with international petroleum supply obligations. The PDR Act deals with demand and distribution issues in a supply crisis.

Stocks

Stockholding structure

As previously noted, New Zealand has no domestic public stocks, and the government does not place a minimum stockholding obligation on industry. All stocks in New Zealand are held on a commercial basis.

Until the acquisition of government-owned ticket reservations, New Zealand relied solely on the industry's normal stockholding practices to meet the country's overall minimum 90-day net-import obligation as a member of the IEA. From 1 January 2007, the New Zealand government acquired ticket reservations for stocks held in other IEA member countries to supplement the country's domestically held commercial stocks.

When New Zealand's domestic production was growing, the country's net imports dropped, thereby reducing its IEA stockholding obligation (and need for tickets). However, since 2010 domestic production has, on average, started to decline and New Zealand's stockholding obligation and need for tickets have once again begun to increase. All tickets are held directly by the New Zealand government, rather than through an agency on the government's behalf.

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Crude or products

As of April 2013, total stocks held by industry in New Zealand stood at around 8 mb, of which 29% were crude and unrefined oils; the rest consisted of finished products.

Location and availability

The New Zealand government has entered into government-to-government agreements with Australia and the United Kingdom and has concluded formal treaties with the Netherlands, Japan and Denmark to enable stocks held in those countries to count towards New Zealand's IEA obligations. In an IEA co-ordinated action, these stocks held outside of the country may be released onto the global market. If needed domestically, the stocks can be purchased and transported directly or swapped with stock held closer to New Zealand in order to reduce transport costs and delivery time.

The ticketed public stocks held in other countries are normally a mix of crude oil and gasoline.

Monitoring and non–compliance

As New Zealand has no compulsory stockholding requirements, there is no monitoring of individual company compliance. The government relies on accurate data from the oil companies in order to assess whether or not the total level of stocks in the country is sufficient to meet the IEA stockholding obligation. New Zealand authorities assure the accuracy of the company reporting by undertaking audits of the information supplied. The IEA Act allows the Minister of Energy and Resources to direct any petroleum-supplying company to keep books, accounts and records, and to furnish returns and information as requested. Any company which fails to comply with these directives commits an offence against the Act and is liable, on summary conviction, to a fine.

Stock drawdown and timeframe

In principle, a release of the stocks held overseas in the form of tickets could be implemented very quickly, with the stocks delivered directly into the local market where they are being held.

With regard to domestically held company stocks, the legal authority to require a stock drawdown is contained in the PDR Act. However, the government's preference would be for NESO to reach a voluntary arrangement with regard to the release of stocks during an emergency or an IEA co-ordinated action.

Any decision to release stocks is the responsibility of the Minister of Energy and Resources in consultation with colleagues, and is expected to take 4 to 10 days. However, depending on where the stock is required, it is estimated to take 15 to 45 days for physical delivery of stocks to the market after the stockdraw decision has been made.

Financing and fees

All industry stockholding costs are recovered by oil companies through their normal operations. The public stock ticket reservations are (as of the end of 2013) financed through the government's general budget.

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Other measures

Demand restraint

New Zealand has a series of demand restraint measures that escalate from voluntary, light-handed measures to more substantive compulsory requirements, depending on the impact and severity of the emergency. As the transport sector makes up 77% of oil consumption in New Zealand (in 2011), the main focus of demand restraint measures is on transport fuels.

Voluntary demand reduction is the lowest level response initiated through a public information campaign encouraging consumers to conserve oil. This could include telecommuting, using public transport, carpooling and staggering work start times to relieve highway congestion. The New Zealand authorities estimate that these measures could reduce the number of trips by approximately 10%, producing a 3.5% (5 kb/d) overall reduction in consumption of oil products.

The public information campaign would also include a detailed promotion of eco-driving, encouraging drivers to use their vehicles as efficiently as possible. This includes voluntary speed reductions, avoiding rush hour traffic, checking the tuning of the car's engine, the condition of its air filtres and the inflation of its tyres. Authorities estimate that these measures would reduce oil consumption by approximately 3% for cars and freight vehicles, resulting in an overall reduction of 2% (3 kb/d).

The country's public information campaign would also target industrial and agricultural users of oil, encouraging them to conserve in different ways. It is estimated that these sectors could achieve a savings of 5% of their consumption, equating to an overall oil savings of 0.5% (0.8 kb/d).

A higher level response is available through the demand restraint provisions of the PDR Act. Allocation and quality rationing are the most complex and substantive response mechanisms available to government.

Fuel switching

New Zealand uses very little oil to generate power or heat, so the scope for petroleum savings from fuel switching is limited.

Other

- *Surge oil production*

  Surging of oil production would take several months to implement and could increase output by 1% to 2%.

- *Relaxing fuel specifications*

  The government has the authority to alter mandatory fuel specifications under the Energy (Fuels, Levies and References) Act 1989 to enable the importing or blending of fuels currently not covered by existing specifications. This would increase the potential range of alternative supply options during an oil supply disruption.

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Gas

Market features and key issues

Gas production and reserves

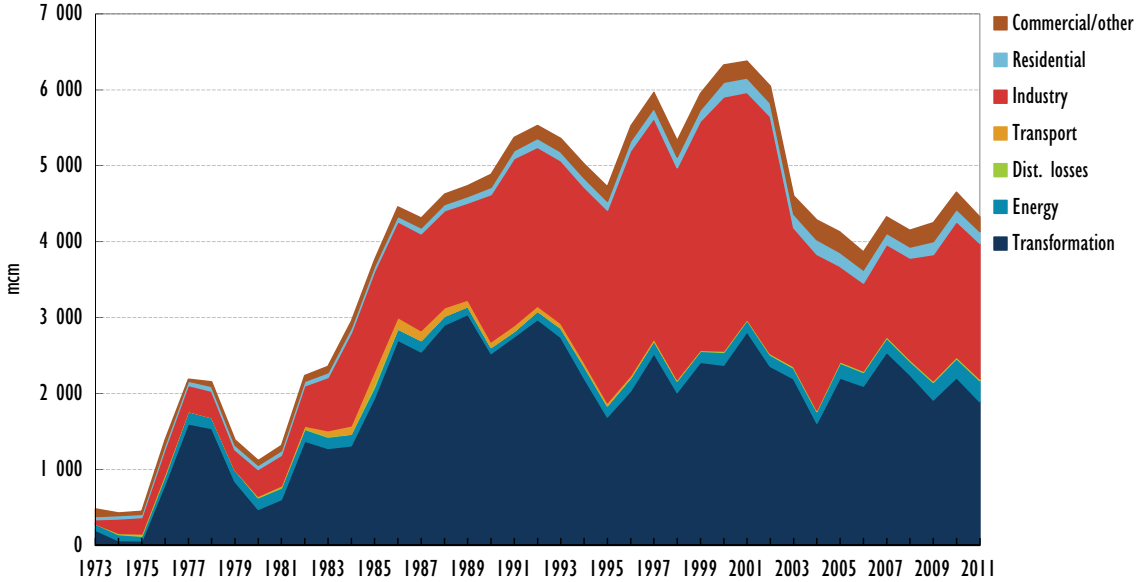
New Zealand has significant domestic natural gas production – enough to meet 100% of the country's natural gas demand. In 2012, natural gas production was 4.6 bcm according to IEA estimates – up from 4.4 bcm in 2011.

As of 2011 there were 17 fields producing natural gas in New Zealand – all located in the Taranaki region of the country's North Island. The majority of production comes from the Pohokura field (38%) and the Maui field (19%).

Gas demand

Gas demand has declined by some 33% since its peak in 2001, and stood at 4.65 bcm in 2012. Demand is dominated by electricity generation (the energy and transformation sectors) which accounted for 50% of total gas demand in 2011 according to IEA figures. (According to government figures, the proportion of natural gas used for electricity generation in 2012 was 44.1%). The proportion of natural gas used for electricity generation in New Zealand is expected to drop rapidly from 2013-14 – with the gas used increasingly for methanol production instead.

Figure 4.19.6 Natural gas demand by sector, 1973-2011



The industry sector is also a significant consumer of natural gas, accounting for 41% of total demand in 2011 according to IEA figures (rising to 46.3% in 2012, according to government figures). The petrochemical industry accounts for around two-thirds of the gas consumed by the industry sector (which it uses to produce methanol and ammonia/urea) and, as noted earlier, the proportion of gas used for methanol production is set to increase. The residential and commercial sectors each only account for 4% of demand according to IEA figures.

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The country's natural gas demand peaks in the winter months, which can extend from May through September, and troughs in summer from November through February. Peak demand on the Maui pipeline is a good proxy for peak demand, as about 80% of gas flows along the Maui pipeline. Four fields have an interconnection into the Maui pipeline: Maui, Pohokura, McKee/Mangahewa and Turangi fields.

The large Maui field has historically been very flexible in terms of production flows, and could thus be modulated in order to meet fluctuating demand. However, with the decline in production rates, the Maui field has lost its flexibility. This has made the New Zealand gas market tighter at moments of peak demand, and partly led to Contact Energy creating the AGS facility.

Gas import dependency

All gas supply in New Zealand is domestically produced in the Taranaki region. New Zealand does not have an LNG import terminal or pipeline connections to other countries, and is therefore entirely reliant on domestic production for its gas needs.

An LNG import terminal has been considered at Port Taranaki to import around half of New Zealand's total annual gas requirements. However, new gas supplies have been brought to the market or are nearing production, and the project has been postponed indefinitely.

Gas company operations

The main upstream producers are Shell, Todd Energy, Origin Energy, Greymouth Petroleum, OMV New Zealand, TAG Oil New Zealand Limited, AWE and NZEC.

Vector runs the Kapuni Gas Treatment Plant which receives raw gas from Shell and Todd.

The biggest distribution and retail companies are Contact Energy, Genesis, Vector, Mighty River Power, Trustpower, Greymouth Petroleum, Novagas, Powerco and Gasnet.

Gas supply infrastructure

Ports and pipelines

New Zealand does not have an LNG import terminal, and so is entirely reliant on domestic production for its gas needs.

New Zealand's North Island has a network of over 3 500 km of high-pressure gas transmission pipelines. Over 2 800 km of intermediate-, medium-, and low-pressure distribution pipelines are connected to the high-pressure system.

All the country's natural gas enters the transmission system in the Taranaki region from both offshore and onshore production. The Maui and Pohokura fields are the largest producers and are connected to the Maui pipeline. Other producers are connected to the Maui or Vector pipelines at various locations around Taranaki.

The Maui pipeline runs from Oaonui and dominates capacity north as far as Rotowaro (near the Huntly Power Plant), although the smaller Vector pipeline runs in parallel. The transmission pipelines north of Rotowaro (through Auckland and up to the refinery), east into the Bay of Plenty and Gisborne, and south of Taranaki (to Wellington and east to Hastings) are all part of the Vector system and are small pipelines relative to the Maui pipeline, typically in the 100 to 300 mm diameter range.

Because of its significantly larger size, balancing across the system is conducted on the Maui pipeline. The Maui pipeline is owned by Maui Development Limited (MDL), which

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is, in turn, owned by Shell (83.75%), OMV (10%) and Todd 6.25%). There is no natural gas production or consumption in the South Island, although several urban centres have small liquefied petroleum gas networks.

Storage

The AGS facility, New Zealand's first underground natural gas storage facility, was officially opened in May 2011. Owned by Contact Energy, the facility has a maximum drawdown capacity of 45 terajoules per day.

The AGS is located close to Contact Energy's 380 megawatt (MW) Taranaki Combined Cycle (TCC) power station and a 200 MW gas-fired peaking power station located near the TCC at Stratford. The facility provides contact with significant natural gas supply flexibility and, if required, can provide sufficient gas to fully supply the peaking units at Stratford. It does not, however, constitute a strategic natural gas reserve.

Emergency policy

A regulated critical contingency management system is in place to achieve the effective management of critical gas outages and other security of supply contingencies without comprising long-term security of supply. The system provides for several contingencies:

- a critical contingency operator (CCO) with powers to require gas consumers to curtail demand
- curtailment bands, which classify non-domestic consumers into groups and which define the order in which the CCO will curtail those groups.

The system is administered by New Zealand's gas industry body – The Gas Industry Company. Declaration and termination of a critical contingency by the CCO, the curtailment and restoration of gas consumption during a critical contingency, and obligations of transmission system operators (TSOs), retailers and consumers before, during and after a critical contingency are the key components of the system.

Emergency response measures

There are no government-mandated requirements on grid owners, system operators or industry participants to hold minimum reserves of natural gas. However, these participants, particularly the system operators, are required to maintain operating pressure in the reticulated network and therefore pipeline owners, system operators and industry participants will hold a certain amount of "reserve gas" as linepack in this respect.

Fuel switching

New Zealand currently has 500 MW of capacity available at Huntly that can be run on coal, natural gas or fuel oil. In a situation where a gas disruption has occurred, this capacity could be run solely on coal. The Huntly power station stockpiles coal on site and is within short proximity of its domestic coal supplier.

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Norway

Key data

Table 4.20.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	1 717.6	3 330.8	2 960.7	2 137.0	2 039.3	1 913.7	1 751.5
Demand (kb/d)	199.4	211.4	216.7	220.8	224.3	218.0	252.6
Motor gasoline	41.4	37.4	36.6	27.8	25.2	23.0	-
Gas/diesel oil	65.6	79.3	84.4	99.6	96.8	98.2	-
Residual fuel oil	12.5	10.4	10.0	7.1	5.8	4.7	-
Others	79.8	84.3	85.7	86.3	96.4	92.1	-
Net imports (kb/d)	- 1 518.2	- 3 119.4	- 2 744.0	- 1 916.2	- 1 815.0	- 1 695.7	- 1 498.9
Import dependency (%)	- 761.5	- 1475.6	- 1266.2	- 868.0	- 809.3	- 777.7	- 593
Refining capacity (kb/d)	295.0	358.0	310.0	316.2	316.2	316.2	-
Oil in TPES (%)**	36	32	35	40	37	37	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.20.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	27 642	53 293	86 946	109 648	105 697	114 748	117 348
Demand (mcm/y)	2 262	4 109	5 186	6 141	5 891	6 156	5 939
Transformation	0	34	64	931	746	0	-
Industry	0	680	818	790	874	0	-
Residential	0	0	6	5	4	0	-
Others	2 262	3 395	4 298	4 415	4 267	0	-
Net imports (mcm/y)	- 25 380	- 49 184	- 81 760	- 103 507	- 99 806	- 108 592	- 111 409
Import dependency (%)	- 1 122	- 1 197	- 1 577	- 1 686	- 1 694	- 1 764	- 1 876
Natural gas in TPES (%)	9	15	15	20	18	17	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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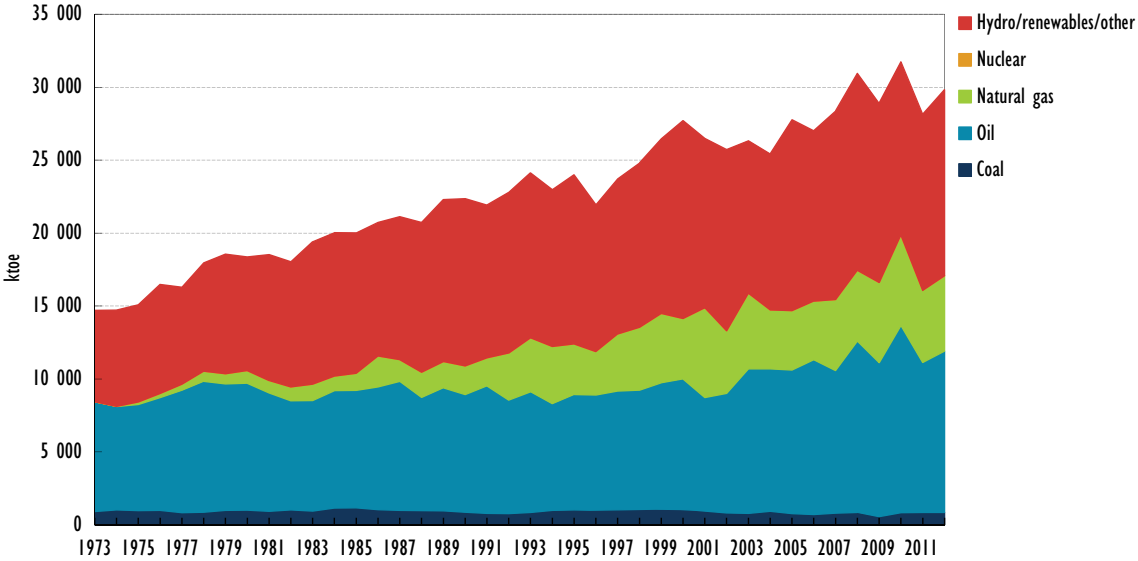
Figure 4.20.1 Total primary energy source (TPES) trend, 1973-2012



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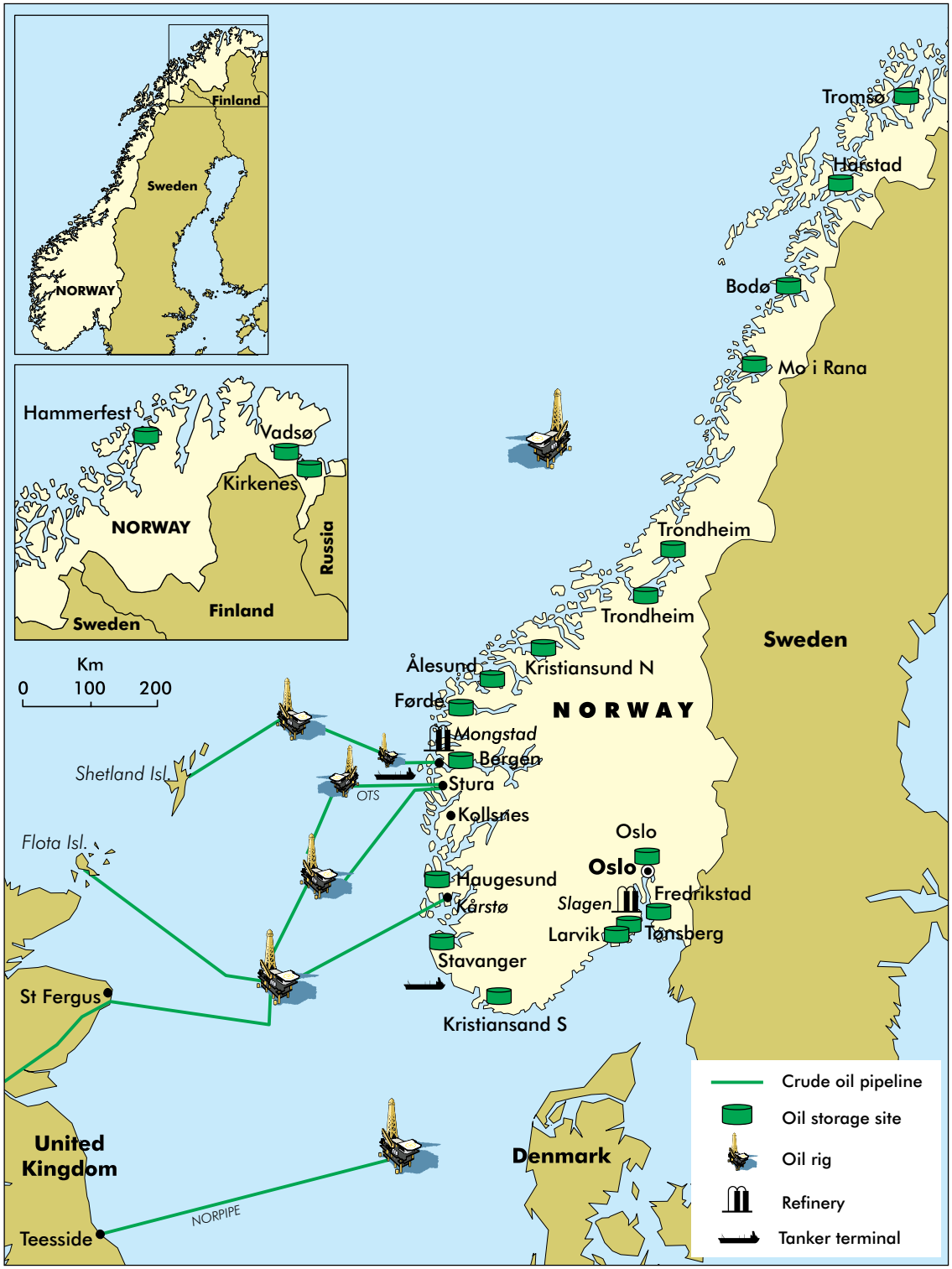
Map 4.20.1 Oil infrastructure of Norway



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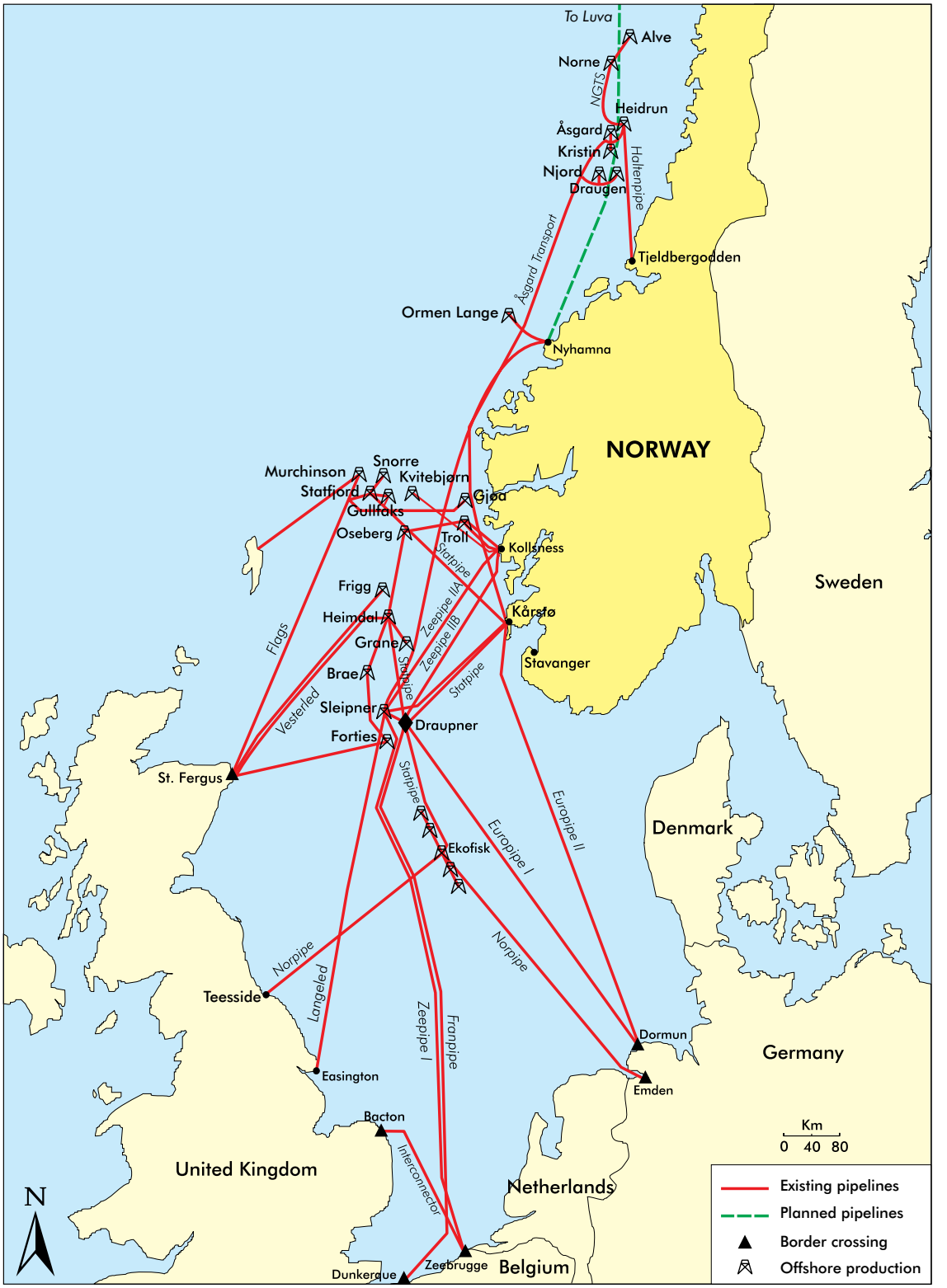
Map 4.20.2 Gas infrastructure of Norway



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Country overview

Norway joined the International Energy Agency (IEA) in 1975, with an agreement allowing the government to decide whether and how (on a case-by-case basis) to join an IEA emergency sharing system, including emergency stockdraw response measures. As Norway is a net exporter of oil, it is not bound by the IEA 90-day stockholding commitment.

Crude oil and natural gas resources on the Norwegian Continental Shelf (NCS) have been the main driver of the growth of oil and gas production in Norway. Since 2002, however, oil production has been declining; in the absence of significant new discoveries, the peak of oil production may already have been reached.

In 2012, Norway produced 1.91 million barrels per day (mb/d). Norway's crude is both light and sweet, and over three-quarters of its production is exported, with over 90% headed to OECD Europe member countries.

Total Norwegian oil demand in 2012 stood at 218 kb/d. Norway's total oil demand has been declining gradually since 2006, with the transportation sector accounting for over half of this demand.

Norway has two refineries: The Mongstad facility (200 kb/d) close to Bergen, and the Esso plant (110 kb/d) at Slagen south of Oslo. Their annual capacity totals about 310 kb/d. Approximately 30% of the output from these refineries (90 kb/d) is consumed by the domestic market, while the rest is exported.

Until 2006, Norway held a certain amount of governmental stocks for oil emergencies. These stocks were sold off in 2007 when new legislation was introduced that obliged the industry to hold emergency stocks of 20 days of their sales/imports in the domestic market. Release of company-held stocks is the preferred action in an IEA collective action responding to an oil supply disruption.

Norway is a significant gas producer. In 2012 its production stood at 114.7 bcm and is forecast to remain so for the coming decades. The Norwegian government has estimated "remaining gas resources" at 4.0 trillion cubic metres (tcm), of which 69% are discovered and 31% are undiscovered resources.

By contrast, Norway is a marginal consumer, exporting almost its entire production. Norway's total gas consumption stood at approximately 6.1 bcm per year in 2012.

Oil

Market features and key issues

Domestic oil production

Norway is a major oil producer, and is one of only three net exporters (along with Canada and Denmark) among the IEA member countries. The bulk of domestic crude oil is produced from offshore platforms operating on the NCS. From the platforms, the crude oil is transported to onshore oil terminals either by pipeline or by loading onto oil tankers for transportation to oil refineries. The Mongstad refinery is linked by pipeline to some of the offshore production.

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Norway produced 1.91 mb/d in 2012. Its crude is both light and sweet, and over three-quarters of its production is exported, with over 90% headed to OECD Europe countries. These volumes make Norway the seventh-largest world oil producer. In 2012, Norway's net exports of oil (including products) stood at 1.7 mb/d.

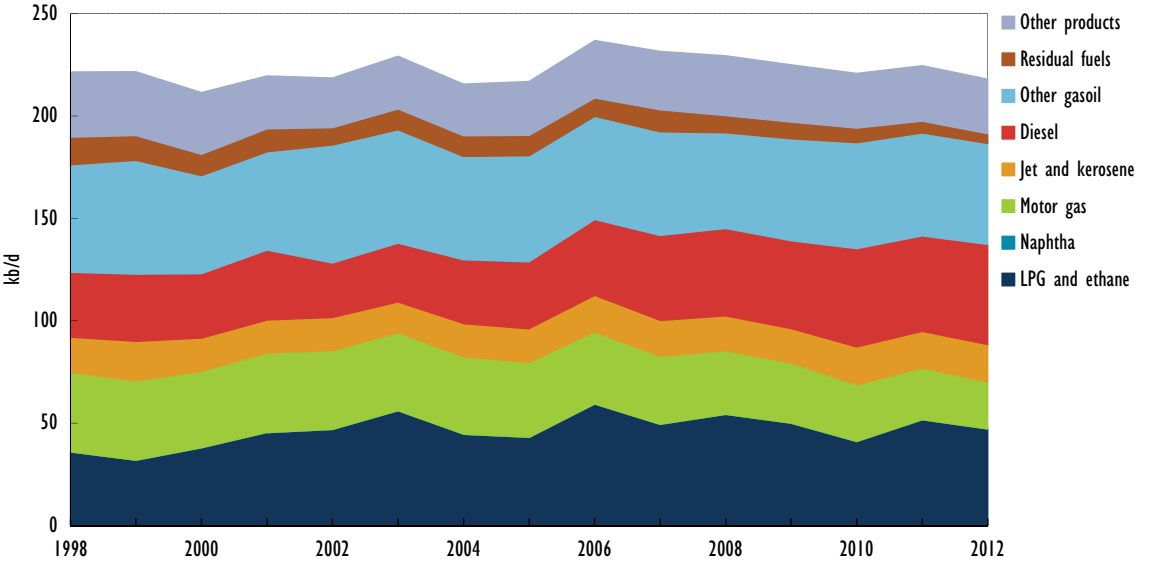
Since 2002, NCS oil production has been decreasing. Should no new resources be exploited, it is expected to have peaked.

In order to meet the challenges related to mature fields, the Norwegian authorities have undertaken several policy changes. The two most important ones are opening the NCS to a wider range of companies and making all exploration areas around mature fields available through annual licensing rounds. There are now two separate systems for licensing on the NCS: one for awarding new licences in frontier areas and one for more mature areas.

Oil demand

Total Norwegian oil demand in 2012 stood at 218 kb/d. Norway's total oil demand has been declining gradually since 2006 and overall demand is expected to continue along this gradual downward trend in the upcoming years, mainly because of a progressive decline in gasoline demand.

Figure 4.20.2 Oil demand by product, 1998-2012



The transportation sector accounted for over half of this demand, with motor gasoline, gas/diesel oil, and jet kerosene being the main transportation fuels. Any future oil demand growth will be the result of increases in the use of these fuels.

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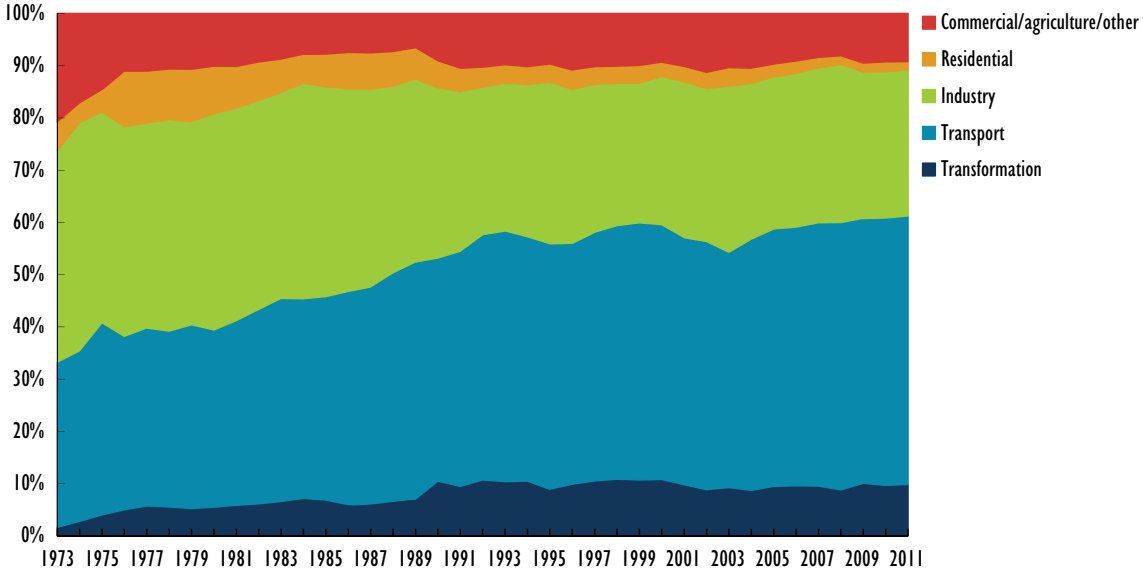
Figure 4.20.3 Oil consumption by sector, 1973-2011



Imports/exports and import dependency

In 2012 Norway's production stood at 1.91 mb/d; 90% of this amount was exported. With its two refineries producing some 328 kb/d of products in a domestic demand market of only 218 kb/d (2012 figures), Norway is also a net exporter of refined products, including both gas/diesel oil and gasoline.

Oil company operations

Nearly 60 oil companies are currently engaged in the upstream sector of the Norwegian petroleum industry. More than one-third of these are appointed operators of one or more production licences. Statoil alone accounts for almost 70% of all activities on the NCS. With the maturing of the NCS fields, there has been a renewed focus on attracting competent new players to the upstream sector. At the end of 2012, the state had participating interests in 158 production licences and 15 partnerships relating to pipelines and onshore installations.

The downstream market is highly concentrated in the hands of a few companies, with the four biggest players – Shell, Statoil Fuel & Retail, Esso and Uno-X – controlling 97% of the combined gasoline and diesel retail market, and the top three alone (Statoil Fuel & Retail, Shell and Esso) accounting for 86% of the market. Statoil has the single biggest market share, with close to 34% of combined motor fuel sales.

Oil supply infrastructure

Refining

Norway has two refineries: The Mongstad facility (200 kb/d) close to Bergen, and the Esso plant (110 kb/d) at Slagen south of Oslo. Their annual capacity totals approximately 310 kb/d.

Approximately 30% of the output from these two refineries (90 kb/d) is consumed by the domestic market, while the rest is exported. The remaining domestic consumption of oil products, amounting to some 140 kb/d, is produced at foreign refineries.

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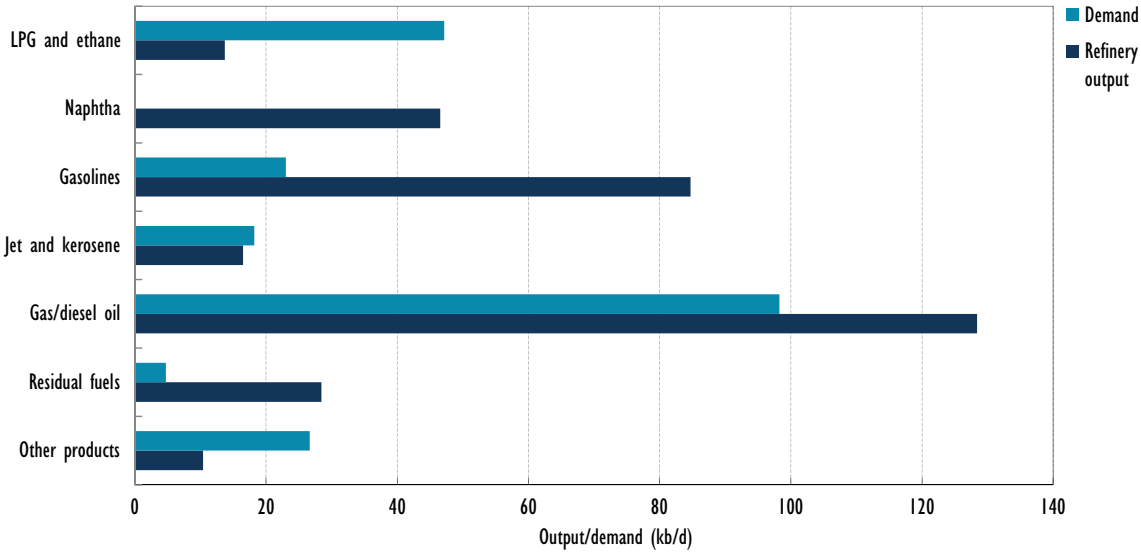
Figure 4.20.4 Refining output vs. demand, 2012



Ports and pipelines

Norway has established an extensive network of sub-sea oil pipelines to link offshore oil fields with onshore terminals. Statoil (previously Norsk Hydro) operates the Oseberg Transport System (765 kb/d) to connect the Oseberg field with the Sture receiving terminal. Statoil also operates another pipeline (265 kb/d) called Grane, linking its Grane field to Sture. The storage capacity of the Sture terminal is 6.3 mb of crude oil.

Statoil also manages the twin pipelines system called Troll I and II (565 kb/d), connecting the Mongstad terminal to offshore oil fields. The terminal can store 9.4 mb of crude oil. Most of the crude is exported from Mongstad by tankers, but the refinery retains a certain amount for its own use.

The Norpipe Oil AS pipeline is operated by ConocoPhillips Skandinavia AS. This oil pipeline (810 kb/d) is about 354 km long, starting at the Ekofisk Centre and crossing the UK Continental Shelf to come ashore at Teeside in the United Kingdom. A tie-in point for UK fields is located about 50 km downstream from Ekofisk.

Norway has numerous ports throughout the country. The main port for the country's oil industry is near Bergen/Stavanger on the west coast, which is linked by pipeline to offshore production, and is connected to the country's main refinery at Mongstad. The region around the capital, Oslo, on the east coast also has notable port activity. The country's other refinery, Slagen, is located at Toensberg, about 100 km south of Oslo.

Storage capacity

Norway has 26 main storage facilities, spread over 17 localities, as well as about 50 distribution storage facilities. If the sub-storage and inland depots are included, altogether Norway has about 400 storage facilities, all owned by Norwegian fuel trading companies.

In addition to the Slagen and Mongstad refineries, which together can store around 15.7 mb of crude oil, Norwegian oil marketing companies have several types of storage facilities, including large storage terminals, distribution storage (supplied by tankers from the refineries or main storages sites) and coastal storage or sub-storage sites for delivering bunker oil to ships (supplied by ship and operated by independent dealers).

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The companies also have larger storage facilities situated on service bases for offshore activity which are operated by the service companies themselves. Additionally, inland depots for small-scale distribution ("peddlers") deliver heating oil and auto diesel to households and agriculture. The products from main storage sites, distribution storage and peddler depots are delivered by trucks. For deliveries to large customers, small tankers or barges are also used.

Several companies have entered into agreements on stockdraw in each other's storage facilities. The agreements reduce distribution costs and are economical for the companies.

Decision-making structure

In an emergency, the formal decision arising from an IEA collective action will be made by the Minister of Foreign Affairs after consultations with the Minister of Petroleum and Energy (MPE). The other cabinet members will be informed in an appropriate way. Depending upon the actual situation, a decision on Norwegian participation might be made within 24 hours after receipt of a proposal for an IEA collective action.

Following the decision to participate in an IEA collective action, the MPE decides on the measures to be taken in an emergency. Under the new compulsory stocks regime, companies are required to release their stocks in an effective manner and immediately.

The stockdraw process (release of industry stocks) will formally be headed by the MPE who will use the Oil Emergency Board (OEB) to administer the process; the OEB is made up of high-ranking representatives from Norwegian oil companies and chaired by the MPE. The operational stock release is undertaken by Statoil ASA or Esso Norway (the two refining companies). The administration indicates that, on request, Statoil ASA's or Esso Norway's stockholding commitments of petroleum products can be lowered progressively, in line with the stockdraw rate and the sales process; the sales process is organised as a tender process.

Stocks

Stockholding structure

Despite being a net exporter, Norway held government stocks until 2006, based on laws established in 1956 (the Act of Supply and Contingency Measures, subsequently amended in 1975).

In August 2006, Norway introduced new legislation with the Act of Petroleum Product Storing for Emergency Purposes, which imposed an obligation on companies to hold stocks of products equivalent to 20 days of their sales/imports in the domestic market, and also an obligation to implement stockdraw upon the government's request, should a situation of supply deficit occur. The Act was provided with supplementary regulations, instituted in September 2006. As a consequence of this new legislation, the government stocks were sold in 2007.

The new regulations give the government control of company stocks during peacetime in the event of a supply disruption. The new stocks legislation covers only petroleum products; however, in wartime the government can take control of all crude oil stocks as well as industry-held product stocks.

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Crude or products

According to the Royal Decree of 1 September 2006 (Regulation relating Petroleum Product Storing for Emergency Purposes), the products that make up the compulsory stockholding obligation embrace the three existing EU categories, namely gasoline (Cat.1), middle distillates (Cat.2) and heavy fuels (Cat.3). At least 40% of the stored products must be made up of each of these three categories (para. 6 of the Royal Decree), and "up to 40% of the total stockholding commitment may consist of crude oil, condensate or semi-finished products".

Location and availability

The new compulsory stocks are commingled with commercial stocks. Although there are no restrictions on location of stocks outside Norway, no stocks are currently held abroad. Norway has no bilateral stockholding arrangements with other countries.

Monitoring and non-compliance

As stipulated in the Royal Decree (para. 10), "Compulsory stockholders or anyone storing petroleum products on behalf of the compulsory stockholder are bound to provide the ministry with information about imports, sales and stocks, etc. on a specific scheme. The report must be submitted four times a year (i.e. before 15th January, 15th April, 15th July and 15th October").

The new legislation includes provision for fines of up to EUR 1.25 million (NOK 10 million) per infringement of the obligation.

Financing and fees

There is no financial support to cover the cost of company stock obligations; companies are allowed to pass on any additional costs through consumer prices.

Other measures

Demand restraint

The transport sector makes up the majority of oil consumption in Norway, representing 51% in 2011. Thus the likely, most effective demand restraint measures would be targeted at the use of transport fuels.

In accordance with the Act on Supply and Contingency Measures, the MPE established a set of regulations for a comprehensive demand restraint programme for oil products in 1983 (revised in 1999). The programme consists of three phases: saving campaigns (based on persuasion), restrictions (light and heavy-handed as well) and rationing by cards.

Norway considers that, in today's oil market, traditional demand restraint measures (such as restrictions on deliveries) are less reliable as measures in an IEA emergency response, and the Norwegian policy is to implement stockdraw measures. This is mainly because of the lengthy preparation time and uncertain effects of demand restraint. However, the legal arrangements from 1983 that allow for the implementation of the demand restraint system have not been formally abolished and are currently dormant.

Rationing by cards has always been regarded as a last resort in Norway and would only be implemented if the government believed that the actual crisis would last for at least six months and domestic consumption had to be cut by 20% or more. Before implementation, a preparation phase of about three months would be required in

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order to make the necessary technical arrangements and extensive preparations for implementation and control of the effects of rationing. Other more light-handed demand restraint measures, such as saving campaigns and restrictions, would already have been put into effect during the preparation phase.

Norwegian authorities consider the oil rationing system to be a sub-optimal measure for mastering peacetime oil supply crises, notably because of the long timeframe needed to prepare for the implementation and the building up of a huge apparatus on both the local and regional level.

Other

Norway has no potential for increasing indigenous production in an emergency.

Fuel switching from oil is very limited and is not an issue on which Norway has focused. Norway's contribution to the IEA's fuel-switching potential would thus be minimal. Of note, no legal powers exist to implement fuel switching.

Gas

Market features and key issues

Gas production and reserves

Norway is a significant gas producer – production stood at 114.7 billion cubic metres (bcm) in 2012 – and is forecast to remain so for the coming decades. All Norway's supplies are thus sourced directly from domestic production on the NCS.

The Norwegian administration has estimated "remaining gas resources" at 4.0 tcm, of which 69% are discovered and 31% are undiscovered resources.

In 2012, the Norwegian administration indicated that total "marketed" gas production was 114.7 bcm, of which 108.6 bcm was exported to Europe by pipeline and 4.7 bcm produced and exported from the Snøhvit liquefied natural gas (LNG) plant in the Barents Sea. The IEA estimates total indigenous production (including gas used for upstream oil and gas production) for 2012 at 114.7 bcm.

The Norwegian administration expects production to range from 105 bcm to 130 bcm over the period from 2010 to 2020, depending on exploration results and when new projects come on stream.

The Snøhvit LNG project was constructed to exploit the resources of three gas fields in the Barents Sea – Snøhvit, Albatross and Askeladd (240 m to 345 m deep) – which lie about 140 km northwest of Hammerfest in Norway. The LNG export terminal was completed in August 2007; its annual export capacity is 5.75 bcm.

Gas demand

Norway is a major producer and exporter of gas, but not a large consumer. Indeed, domestic use of gas amounts to a very small percentage of the country's gas production. In 2012 total gas consumption stood at approximately 6.1 bcm.

Gas use for power is very small, standing at 229 million cubic metres (mcm) in 2012 – accounting for 1.7% of total power input. The biggest consuming sector of natural gas is industry, particularly as natural gas is used as a raw material in chemical production and in small-scale LNG plants. Consumption is minimal in all other sectors.

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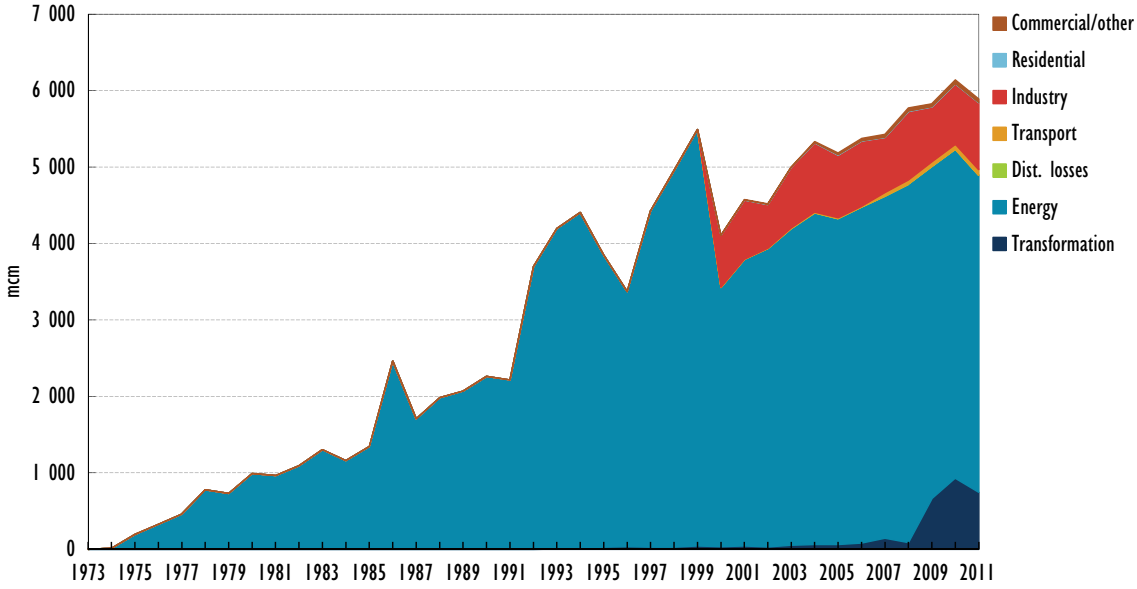
Gas exports

Norway consistently exports almost 95% of its gas production (108.6 bcm in 2012, out of 114.7 bcm produced). Exports have traditionally been to Europe by direct pipeline (to the United Kingdom, France, Belgium and Germany). Since the Snøhvit LNG terminal started exports in 2007, Norway's exports have become further diversified.

Figure 4.20.5 Natural gas consumption by sector, 1973-2011



Gas company operations

In Norway, there are two main natural gas distributors, Gasnor AS and Lyse Gass AS. Gasnor operates in the southwestern part of Norway, and Lyse Gass operates in the Stavanger area. Lyse Gass AS has reported the delivery of 61 mcm (599 gigawatt hours) of gas in 2012. Gasnor has reported delivery of 222.9 mcm in 2012.

Gas supply infrastructure

Ports and pipelines

There is no integrated national downstream natural gas infrastructure or natural gas market covering Norway in a comprehensive manner. Norway also has no public or strategic storage of natural gas or LNG.

The pipelines built in Norway cover very limited geographical areas:

- Gasnor has approximately 100 km of pipelines in the southwestern part of Norway, in the Haugesund-Karmøy region
- Lyse Gass AS has approximately 450 km of distribution pipelines and distributes natural gas to a very limited geographical area in the southwestern part of Norway, in the Stavanger area.

Small-scale LNG-distribution has become a Norwegian alternative to gas transmission and distribution networks. In 2007, there were around 30 LNG reception terminals in operation in Norway. No household customers are served from these small-scale LNG reception terminals.

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Gassco is the operator of the integrated gas transport system from the NCS to other European countries. The creation of Gassco forms part of an extensive reorganisation of the Norwegian oil and gas sector since 2001. Before that date, gas transport was provided by a number of companies. The Norwegian administration has also indicated that Gassco serves as the operator for the gas receiving terminals in Dunkerque, France, Zeebrugge, Belgium and Emden and Dornum in Germany.

Emergency policy

The Norwegian Water Resources and Energy Directorate is the national independent regulatory authority for the downstream natural gas market, and Norway has implemented the relevant EU directives.

According to the Norwegian administration, security of supply is not an issue in the poorly developed Norwegian downstream gas market. Indeed, natural gas customers in Norway will always be connected to the electricity grid, thereby supplying them with energy for various needs.

Unlike in many other IEA member countries, natural gas is not a key source of power generation. In fact, hydro alone consistently accounts for over 96% of electricity production.

However, during the winter of 2002-03, Norway experienced a drought followed by a cold wave, severely depleting its hydro reserves and making electricity rates rise fourfold in a matter of weeks. In response, Norway's first commercial onshore gas-fired power plant was built by Naturkraft at Kårstø. Interestingly, the 420 MW plant claims to have the lowest greenhouse gas emissions of any fossil fuel power plant in Europe, at a cost of around EUR 253 million (NOK 2 billion).

The Kårstø plant uses gas resources from the NCS and started electricity production in the winter of 2007. The project can theoretically deliver up to around 3% of Norway's total electricity production (equivalent to around 175 000 households). The plant can use up to 600 mcm of natural gas per year, or approximately 0.5% of Norway's annual gas exports. However, owing to commercial considerations linked to gas and power prices, the production of power from Kårstø has been small over the past few years.

Five gas turbines also provide power to Statoil's LNG plant from gas sourced from the Snøhvit field.

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Poland

Key data

Table 4.21.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	3.0	14.5	28.0	19.3	18.2	19.8	13.8
Demand (kb/d)	280.1	411.3	470.4	564.2	559.5	521.6	560.4
Motor gasoline	71.5	115.6	92.8	97.7	92.4	89.3	-
Gas/diesel oil	101.5	149.1	195.2	264.1	274.0	253.0	-
Residual fuel oil	51.7	40.6	36.6	30.3	26.0	20.7	-
Others	55.5	106.0	145.9	172.0	167.0	158.6	-
Net imports (kb/d)	277.1	396.8	442.4	544.9	541.3	501.8	546.5
Import dependency (%)	98.9	96.5	94.0	96.6	96.7	96.2	98
Refining capacity (kb/d)	0.0	382.0	350.0	507.0	507.0	507.0	-
Oil in TPES (%)**	13	21	23	25	25	25	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.21.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	4 095	5 224	6 057	6 079	6 247	6 193	5 684
Demand (mcm/y)	12 096	13 346	16 231	17 155	17 178	18 112	18 512
Transformation	833	947	2 076	2 059	2 127	0	-
Industry	6 060	5 517	6 381	6 292	6 662	0	-
Residential	3 995	4 083	4 280	4 690	4 312	0	-
Others	1 208	2 799	3 494	4 114	4 077	0	-
Net imports (mcm/y)	8 001	8 122	10 174	11 076	10 931	11 919	12 828
Import dependency (%)	66.1	60.9	62.7	64.6	63.6	65.8	69
Natural gas in TPES (%)	9	11	13	13	13	14	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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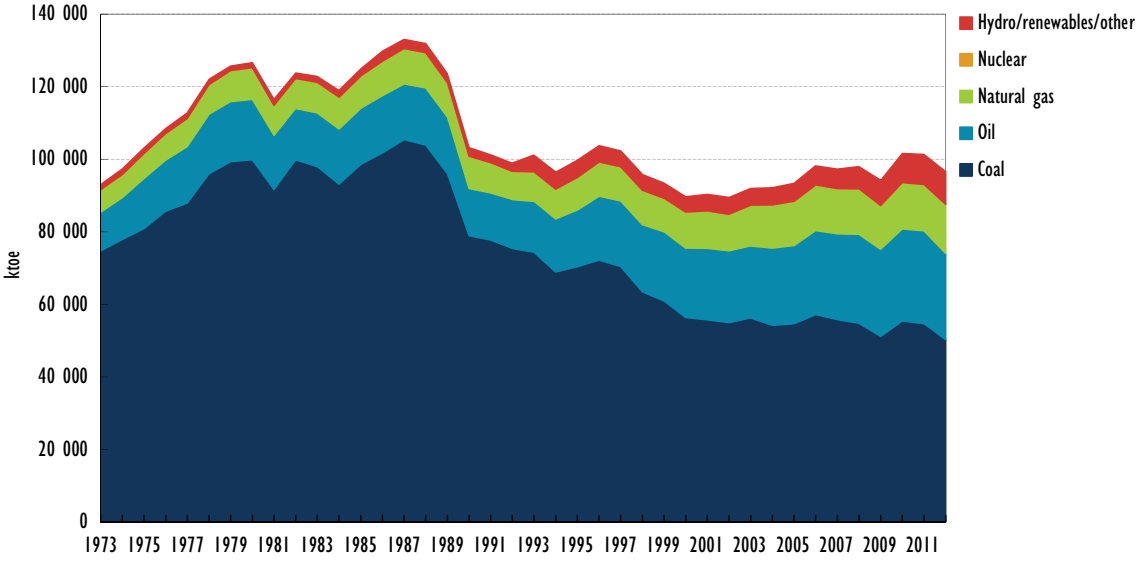
Figure 4.21.1 Total primary energy source (TPES) trend, 1973-2012



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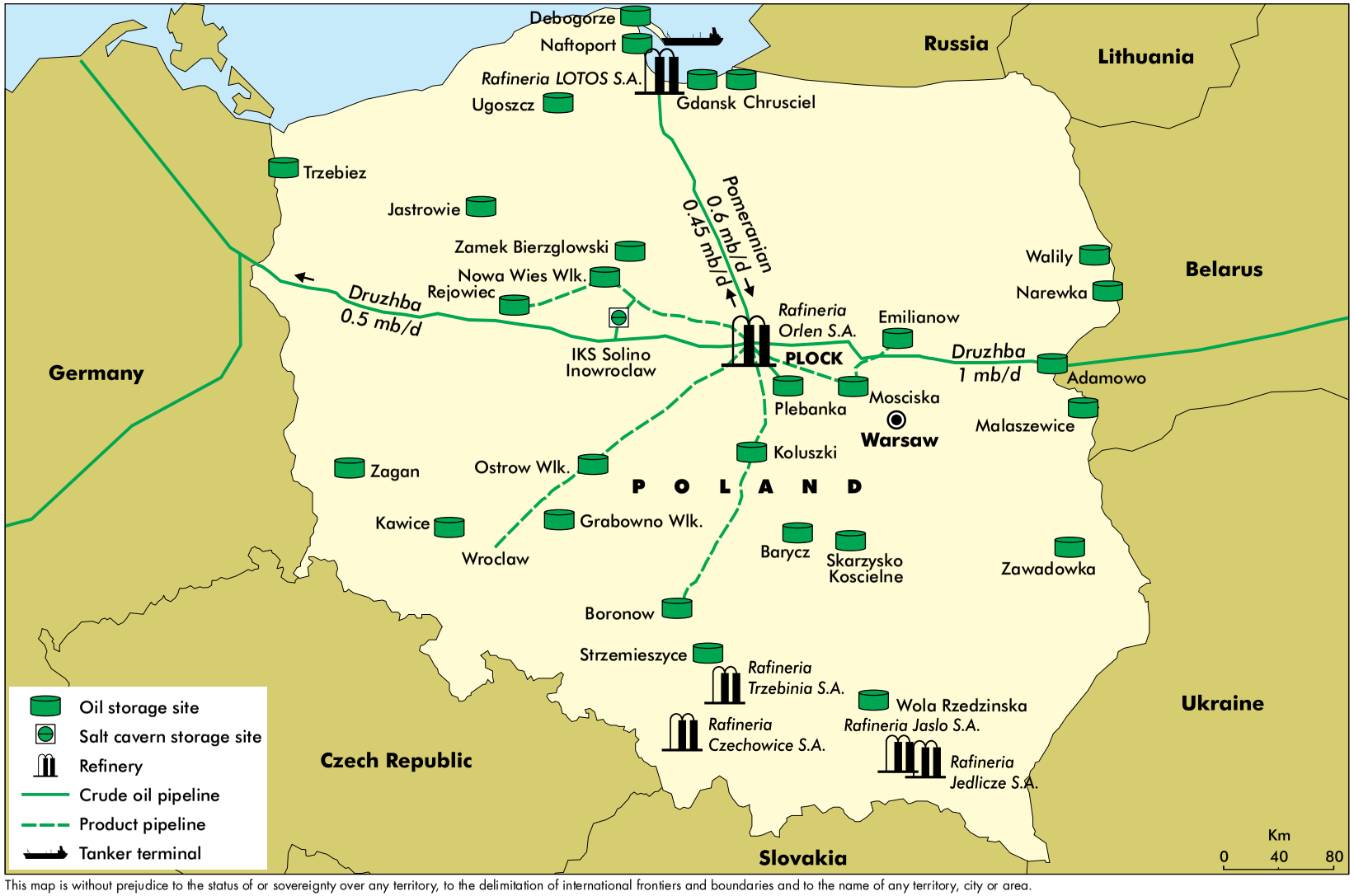
Map 4.21.1 Oil infrastructure of Poland



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Map 4.21.2 Gas infrastructure of Poland

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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Country overview

Oil remains the second biggest energy source in Poland, representing 25% of the country's total primary energy supply (TPES) in 2012. Poland's oil demand has increased from 411 thousand barrels per day (kb/d) in 2000 to 522 kb/d in 2012, with an annual average growth rate of 2%. The transport sector accounted for around 64% of Poland's total oil consumption in 2011. With a small indigenous oil production, almost all the crude oil used in Poland is imported. Poland's oil imports in 2012 were 608 kb/d, consisting of 500 kb/d of crude oil, natural gas liquids (NGLs) and feedstock, and 104 kb/d of refined products. The Russian Federation is Poland's single largest source of crude oil imports and provided about 96% of the total in 2012. Crude oil imports from Russia are through the Druzhba pipeline. In 2012, about 36% of Poland's refined product imports also came from Russia, while 20% of refined products were imported from Germany – Polanda's two most important import sources. There are six refineries in Poland, with a total primary distillation capacity of around 580 kb/d. *Polski Koncern Naftowy* (PKN) Orlen and Grupa Lotos account for almost the entire Polish refining industry.

Poland meets its stockholding obligation to the International Energy Agency (IEA) and the European Union by holding 14 days of government stocks and by placing a stockholding obligation on industry. All liquid fuel producers and importers are obliged to hold 76 days of stock based on their production or imports of crude oil and liquid fuels from the previous calendar year. Under the direction of the Ministry of Economy, the Material Reserve Agency (MRA) manages the state-owned oil emergency reserves and also monitors the stockholding obligation on industry. The use of emergency oil stocks is central to Poland's emergency response policy. Demand restraint is considered as a secondary response measure which might be introduced in a long-lasting and severe crisis.

The share of natural gas in the country's TPES stood at 14% in 2012. Gas demand has steadily increased from 13.3 billion cubic metres (36.6 million cubic metres per day) in 2000 to 18.1 bcm (50 mcm/d) in 2012, with an annual average growth rate of 2.6%. Poland produced about 6.1 bcm (16.7 mcm/d) of natural gas in 2012, which accounted for around 34% of the country's demand. Poland's total natural gas imports in 2012 amounted to 12 bcm (33 mcm/d). Russia has been the principal source of natural gas imports, accounting for 80% of total gas imports in 2012.

Diversification of supply sources and routes, development of natural gas infrastructures for such diversification, expansion of underground storage capacity and an increase in domestic gas production are the key elements of Poland's gas security policy. Gas traders and importers are obliged to maintain 30 days of compulsory gas stocks in Poland.

The Minister of Economy is authorised to decide on the use of compulsory stocks. GAZ-SYSTEM, the transmission system operator (TSO) for natural gas, is responsible for conducting a withdrawal of compulsory gas stocks, in co-ordination with the company Polish Petroleum and Gas Mining, Poland's storage system operator (SSO). The maximum withdrawal rate from domestic storage facilities is some 37 mcm/d, equivalent to about 74% of average gas demand in 2012.

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Oil

Market features and key issues

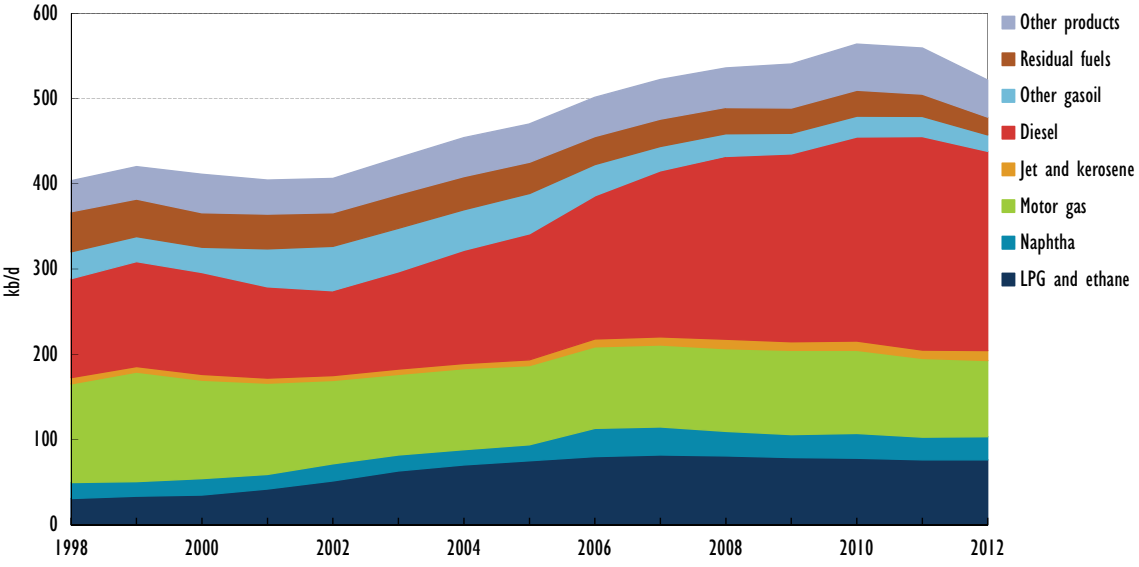
Domestic oil production

Poland has no significant proven reserves of crude oil, and indigenous crude oil production is very small. In 2012, Poland produced 19.8 kb/d of crude oil, which covered less than 4% of the country's total oil demand.

Oil demand

Poland's oil demand increased from 411 kb/d in 2000 to 521 kb/d in 2012, with an annual average growth rate of 2%.

Figure 4.21.2 Oil demand by product, 1998-2012



The transport sector accounted for 64% of the total oil consumption in Poland in 2012. In terms of oil demand by product, demand for diesel increased by 70% in the period between 2000 and 2012 (from 149 kb/d to 253 kb/d), while demand for gasoline declined by 23% in the same period (from 115.6 kb/d to 89.3 kb/d). The use of LPG has risen over the past decade, as this fuel has become more competitive relative to gasoline. Demand for LPG has more than doubled from 35 kb/d in 2000 to 76 kb/d in 2012.

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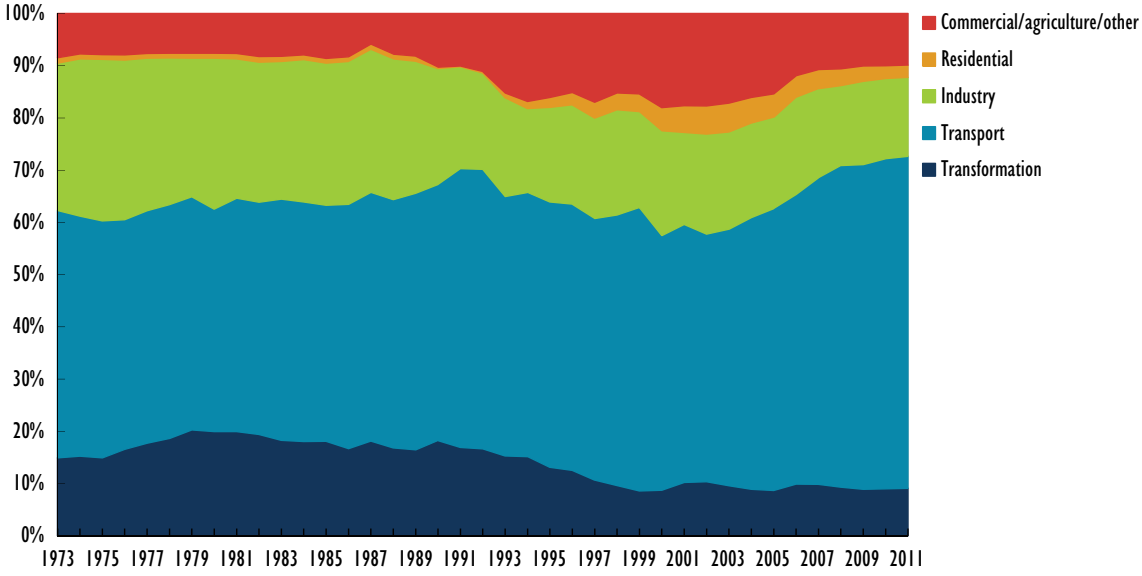
Figure 4.21.3 Oil consumption by sector, 1973-2011



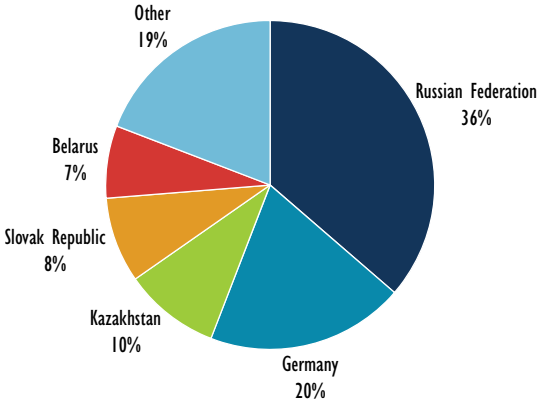
Imports/exports and import dependency

Poland's oil imports in 2012 were 608 kb/d, consisting of 500 kb/d crude oil, NGLs and feedstock, and 108 kb/d refined products. Russia is the single largest source of crude oil imports and provided 96% of the total in 2012. Crude oil imports from Russia are delivered via the Druzhba pipeline. In 2012, the remaining portions of crude oils were imported from Norway (3% of the total) and several other countries, including Iraq, Algeria and Saudi Arabia. Crude oil is imported by refiners mainly based on commercial long-term contracts.

In 2012, 36% of the refined product imports came from Russia, 20% from Germany, 10% from Kazakhstan, 8% from Slovakia and 7% from Belarus. The remaining 19% came from a wide variety of other countries.

Poland exported over 110 kb/d of oil in 2012, consisting of 4 kb/d of crude oil and 108 kb/d of refined products – a sharp increase from 70 kb/d in 2010 and just 40 kb/d in 2000. All crude oils were exported to Germany, while refined products were destined principally to the Netherlands (27%), Denmark (9%) and the United Kingdom (7%).

Figure 4.21.4 Oil product imports by origin, 2012



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Oil company operations

Poland has a dense network of fuel stations owned by Polish companies PKN Orlen S.A., and Grupa LOTOS SA, as well as stations belonging to foreign companies such as BP, Shell, Statoil and Lukoil and independent operators. The total number of fuel stations amounted to over 6 700 in 2012, of which some 3 000 were owned by independent operators.

Oil supply infrastructure

Refining

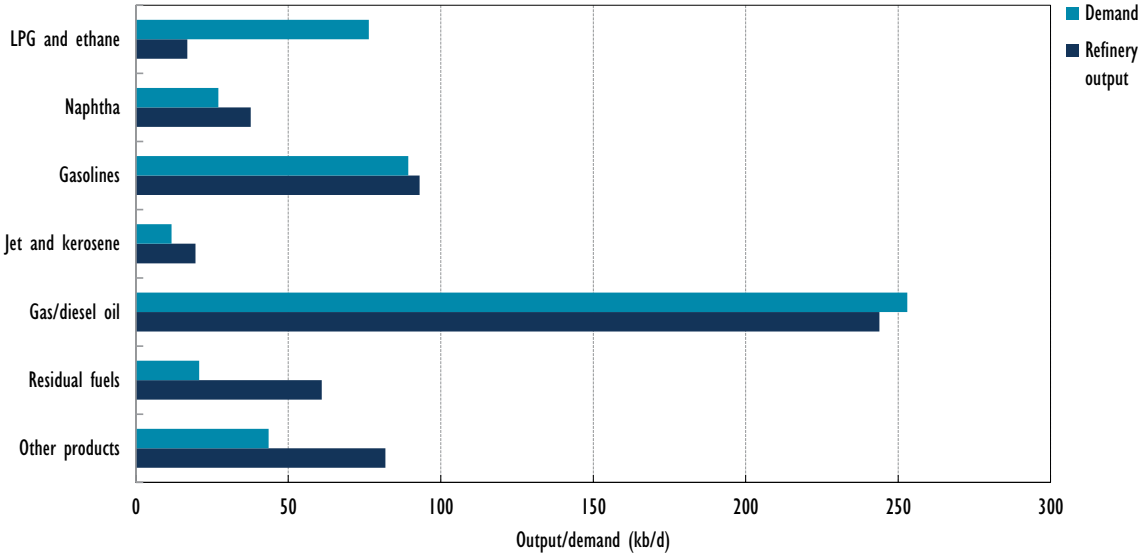
Poland has six refineries with a total primary distillation capacity of around 580 kb/d – or 28 million tonnes (Mt) – per year. PKN Orlen and Grupa Lotos account for almost the entire Polish refining activity.

Płock Refinery, which is owned by PKN Orlen and located in the central region of the country, has a total crude distillation capacity of 355 kb/d. Grupa Lotos owns Gdansk Refinery, the second largest refinery (216 kb/d) in Poland. These two major refineries account for over 95% of the country's total refining capacity. Both Płock Refinery and Gdańsk Refinery process mainly REBCO (Russian Export Blend Crude Oil).

The remaining four refineries are located in the southern part of Poland and have very small processing capacities. Two of them (in Jasło and Czechowice) are no longer operational.

In 2012, the four operating refineries (in Płock, Gdańsk, Jedlicze and Trzebinia) processed around 554 kb/d of crude oil (including NGL and feedstocks). The utilisation rate in 2012 was 96%. In the same year, the composition of total production from these refineries was gasoline (17%), gas/diesel oil (44%), residual fuel oil (11%), naphtha (7%) and LPG (3%). The refineries were able to meet or exceed demand in all products except LPG and ethane (by a shortfall of 59.5 kb/d) and gas/diesel oil (by a slight shortfall of 9 kb/d) in 2012.

Figure 4.21.5 Refinery output vs. demand, 2012



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Ports and pipelines

Poland has three oil port terminals. The main oil port terminal is in Gdańsk and has a capacity of about 700 kb/d (34 Mt/yr). Naftoport Ltd. owns and operates the four jetties in Gdańsk Port. Some 67% of the Naftoport's shares are held by the joint stock Oil Pipeline Operation Company "Friendship" SA (PERN). The remaining portions are held by PKN Orlen (18%), Grupa Lotos (9%) and others.

In 2012, over 10 Mt of crude oils and fuels were loaded and discharged at Naftoport's jetties in the Port of Gdańsk, of which 74% were crude oils and 24% refined products. The Port of Gdańsk is used primarily for exports of Russian crude oils. In addition, there are two small oil terminals for imports of oil products; the Port of Gdynia (with a capacity of 3.5 Mt/yr or 70 kb/d) and Szczecin (1.5 Mt/yr or 30 kb/d).

The Druzhba and the Pomeranian are the main pipelines for transporting crude oil in Poland. These two pipelines supply Russian crude directly to the refineries at Płock and Gdańsk, to Naftoport for exports and transit volumes on to the German refineries at Schwedt and Spergau.

The Polish branch of the Druzhba pipeline is composed of two main sections. The eastern section runs from the Belarus border in Adamowo to Płock, which has a nominal capacity of some 870 kb/d (43 Mt/yr), however, with the use of a drag-reducing agent (DRA) it can transport up to 1 mb/d (50 Mt/yr). A third line, which is under construction, will help to keep the capacity of the eastern section on the level of 1 mb/d (50 Mt/yr) with a significant reduction in operating costs. The western section of the Druzhba pipeline links Płock to the German border in Schwedt, which has a capacity of some 545 kb/d (27 Mt/yr).

The Pomeranian Pipeline can transport crude oil in two directions between Gdańsk and Płock. In the direction from Gdańsk to Płock, the line has a capacity of 0.6 mb/d (30 Mt/yr), while the capacity is 0.45 mb/d (22 Mt/yr) in the opposite direction. This is the route for Russian oil destined for the refinery in Gdańsk and also for export through Naftoport.

Storage capacity

In 2012, Poland had a total storage capacity of 72.7 mb. Roughly 60% of its total storage capacity is used for crude oil.

In terms of crude storage capacity by owner, 60% of the total storage capacity was owned by PKN Orlen. The remaining portions were held by PERN (34%) and Grupa Lotos (6%). In terms of product storage capacity, OLPP, part of the PERN Group, is the biggest storage capacity holder (49%); this is followed by PKN Orlen (33%) and Grupa Lotos (14%).

PERN plans to expand its total storage capacity by about 21.4 mmb by 2015, by constructing additional crude storage depots in Płock, Gdańsk and Adamowo.

In response to the expected increase in demand for storage capacity, PERN and Grupa Lotos are considering building underground salt caverns for crude oil and fuel storage in the Pomorski (Pomerania) region near Gdańsk. The caverns are projected to have a total capacity of around 38 mb.

Emergency policy

The Minister of Economy is responsible for Poland's energy security policy, including its oil emergency response policy. The Governmental Group on Energy Emergency Management serves as the core body of the Polish national emergency strategy organisation (NESO). The group is headed by the Deputy Minister of Economy and is

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composed of representatives from the relevant ministries and governmental entities such as the Energy Regulatory Office and the MRA.

In the event of a domestic supply disruption, the response action is undertaken upon the request of *voivods* (local authorities), producers or traders of fuels or an eligible entity. Each request is evaluated by the Department of Oil and Gas of the Ministry of Economy, which proposes to the minister appropriate response measures to be taken. During a global supply disruption, the Minister of Economy will make the political decision to participate in an IEA collective action and on emergency response measures.

Stocks

Stockholding structure

Poland meets its stockholding obligation to the IEA and the European Union by holding 14 days of government stocks and by placing a stockholding obligation on industry.

All liquid fuel producers and importers are obliged to hold minimum stock levels based on their production or imports of crude oil and liquid fuels during the previous calendar year.

Under the direction of the Ministry of Economy, the MRA manages the state-owned oil emergency reserves and also monitors the stockholding obligation on industry.

The Act of 16 February 2007 also obliges producers and traders to maintain mandatory stocks of LPG at levels corresponding to at least 30 days from the end of 2011.

Crude or products

At the end of December 2012, the MRA held some 8.2 mb of government stocks. Nearly 90% of the public stocks were maintained in the form of crude oil, while the remainder was in middle distillates (10%) and motor gasoline (1%).

Industry stocks in Poland at the end of December 2012 stood at some 55.3 mb, equal to 87% of the country's total stocks (117 days of 2011 net imports). Obligatory industry stocks may be commingled with operational and commercial stocks.

Location and availability

Poland has no bilateral agreements on stockholding with other countries. No public stocks can be held outside the territory of Poland.

The public stocks of crude oil are held mainly in storage tanks rented from PERN, with some amounts in the salt dome storage facilities of PKN Orlen. Public gasoline and diesel oil stocks are held in storage rented from the OLPP, Poland's leading company that offers storage services of emergency stocks and obligatory reserves of petroleum products.

Monitoring and non-compliance

Oil companies with stockholding obligations need to submit data on the quantity of stocks and their location MRA by submission of monthly reports on oil stocks. Non-compliance with this reporting obligation is subject to financial penalties. The MRA submits the consolidated data to the Ministry of Economy on a monthly basis.

Stock drawdown and timeframe

The use of emergency oil stocks is central to Poland's emergency response policy. The Minister of Economy is authorised to decide on the release of government stocks or mandatory industry stocks.

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Public stocks could be made available to the oil industry through a number of options, including auction, tender or sales to specific entities, although these specific companies are not identified in advance. In case of of a release of state stocks of crude oil, refiners may be required to process crude oil for specific products according to instructions from the ministry.

Industry stocks would be made available either by the reduction of the minimum stockholding obligation or by instructing industry to make a compulsory stockdraw.

The Council of Ministers has, upon a proposal of the Minister of Economy, the authority to include commercial stocks owned by producers and traders in compulsory stocks.

Financing and fees

Government stocks are financed from the state budget. No financial assistance or public funding is provided to industry to meet emergency reserve requirements; these costs are therefore passed on to the consumer.

Other measures

Demand restraint

Demand restraint is considered as a secondary response measure which might be introduced in a long-lasting and severe crisis. The decision-making procedure of demand restraint measures is expected to be longer and more complex than that of stock release, as introduction of these demand restraint measures needs the ordinance of the Council of Ministers.

Poland's demand restraint measures would range from light-handed measures to compulsory measures. Light-handed measures include information campaigns to promote eco-driving and use of public transport. Compulsory measures include restrictions on trade in fuel by limiting the maximum quantity of fuel sold by the filling station, the maximum quantity of fuel which a consumer may purchase in a single transaction and the opening hours of petrol stations for fuel sales, as well as restrictions on fuel consumption through speed limits, limiting or ban on distribution of fuel in canisters, a driving ban, rationing of fuel, etc.

Implementation of demand restraint measures is not planned in a pre-crisis situation or in the early stage of a crisis, because of the restrictive nature of the measures. No automatic triggers exist to implement specific demand restraint measures.

Fuel switching

Short-term fuel switching from oil to other fuels is not considered an emergency response measure in Poland, as such fuel-switching capacity in the transformation sector is estimated to be insignificant. Poland does not have a specific policy or legislation to promote short-term fuel switching in an emergency.

Other

Because of Poland's small indigenous oil production (less than 4% of total demand) and lack of spare crude oil production capacity, surge production of oil is not considered an emergency response measure in Poland.

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Gas

Market features and key issues

Gas production and reserves

According to the *BP Statistical Review of World Energy 2013*, Poland possessed 100 bcm of proven reserves of natural gas at the end of 2012; this would be sufficient for approximately 27 years at current production rates.

Poland produced some 6.2 bcm (17 mcm/d) of natural gas in 2012, which accounted for about 34% of the country's demand. The Polish Petroleum and Gas Mining Company (PGNiG) is the dominant producer of gas and crude oil in Poland, representing 98% of domestic gas production from conventional gas deposits.

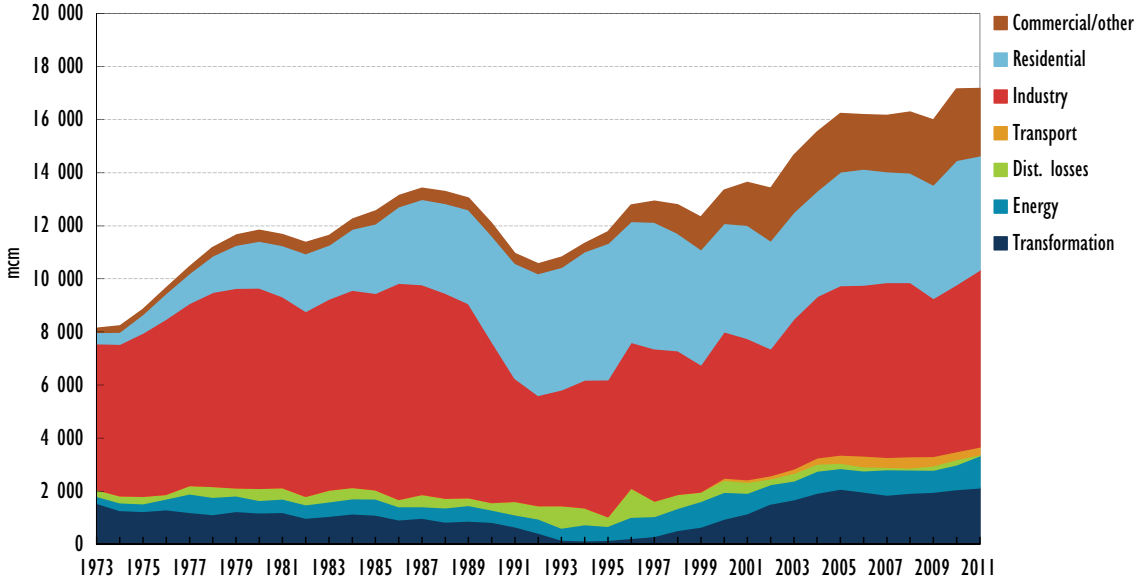
Unconventional gas might offer a potential to change the energy landscape in Poland. Preliminary estimates suggest that Poland could have between 1.4 to 3 trillion m³ of unconventional gas. If the shale gas resources are confirmed, theoretically their large-scale exploitation could render Poland independent of imports and turn the country into a net exporter.

Gas demand

Gas demand steadily increased from 13.3 bcm (36.6 mcm/d) in 2000 to 18.1 bcm (50 mcm/d) in 2012, with an annual average growth rate of some 2%. An 8% increase of demand, to 15.5 mcm, is forecast in 2018.

In 2011, the largest amount of natural gas, 39%, was consumed by Poland's industry. The residential and commercial sectors consumed 25% and 15%, respectively, while just 7% was used for transformation (electricity and heat). Poland's energy industry (most importantly refineries) consumed 7% of the total in 2011.

Figure 4.21.6 Natural gas consumption by sector, 1973-2011



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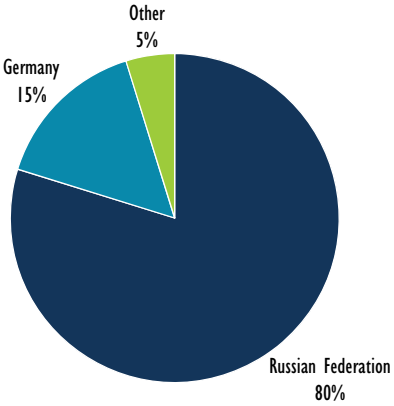
Gas import dependency

Poland's total natural gas imports in 2012 amounted to some 12 bcm (32.8 mcm/d). Virtually all imported gas is supplied through pipelines by PGNiG except for very small quantities of LNG transported by PGNiG's competitors by road in tankers.

Russia has been the principal source of natural gas imports. The share of Russian gas in Poland's total gas imports stood at 80% in 2012, while gas imports from Germany accounted for 15% in the same year.

Figure 4.21.7 Natural gas imports by source, 2011



In October 2010 the 1996 long-term contract between PGNiG and Russia's Gazprom was amended. Under this new contract arrangement, as of 2012 Gazprom will increase its gas supply to Poland to 11 bcm. The supply contract will end in 2022. The destination clause forbidding re-export of Russian gas to other countries was removed from this contract.

Gas company operations

PGNiG has a main position in both upstream and downstream sectors of the industry. It is practically the only importer of gas and it has booked nearly 100% of transmission capacity at all entry points. Being also the major domestic gas producer (98% of domestic production), it effectively controls the wholesale gas market.

PGNiG is also the only owner and operator of underground gas storage (USG) capacity – so far no other company has decided to develop an UGS facility in Poland. In 2008, the regulator appointed PGNiG as the SSO for its USG facilities for 27 years.

As part of the market reform, the ownership of the gas transmission assets of the incumbent PGNiG were unbundled. An independent TSO fully owned by the state – OGP GAZ-SYSTEM – was established in 2004. In 2007, six regional distribution companies were legally unbundled from PGNiG and granted the status of distribution system operators (DSOs).

PGNiG is a leader on the retail market: several other companies (including G.EN Gaz Energia, CP Energia, EWE Polska, Enesta SA and KRI SA) have entered the market but their total market share was about 5% in 2012.

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Gas supply infrastructure

Ports and pipelines

Poland is a key transit country for Russian gas to Western Europe through the Yamal pipeline. The Polish gas system is connected with the European gas network system but mostly along the east-west axis.

Natural gas is imported into the transportation system of Poland throu four key entry points : Lasów (from Germany), Drozdowicze (from Ukraine), Wysokoje (from Belarus) and Kondratki (from Belarus through the Yamal pipeline). The Polish gas transmission system currently includes 9 768 km of pipelines, 14 compressor stations and 854 gas stations.

The flow of gas through the Yamal pipeline has been reversible since the end of 2013.

Poland's first LNG terminal is planned at Świnoujście. Polskie LNG SA, a 100% subsidiary of the OGP GAZ-SYSTEM SA, is to construct, own and operate the LNG terminal. In the first stage of operation, the LNG terminal will enable the regasification of 5 bcm (13.7 mcm/d) of natural gas annually. In the next stage, it will be possible to increase the dispatch capacity to 7.5 bcm/yr (20.5 mcm/d), depending on gas demand. In 2009, Qatargas and PGNiG signed a sales and purchase agreement for LNG supply from Qatar. Under the agreement, Qatargas will supply 1.5 bcm of LNG annually to PGNiG under a 20-year long-term agreement, starting in 2014.

Storage

There are eight underground gas storage facilities in operation in Poland. Their full capacity (1 838 mcm) is equal to 39 days of the average gas demand in 2011 and 55 days of average gas imports in 2011. The maximum withdrawal rate of these storage facilities is some 37 mcm/d, which covered about 79% of average gas demand in 2011 and 58% of the average daily demand in January 2011 (63.3 mcm/d). In the last decade, Poland's highest average daily peak demand was in January 2006, reaching 77 mcm/d.

PGNiG owns all underground gas storage facilities in Poland. With the exception of the portion (50 mcm) made available to OGP GAZ-SYSTEM, PGNiG is the only user of gas storage facilities in Poland. PGNiG plans to expand the storage capacity from the current level of 1.8 bcm to 2.8 bcm by 2021.

Emergency policy

Diversification of supply sources and routes, development of natural gas infrastructures for such diversification (including construction of an LNG terminal and interconnectors), expansion of underground storage capacity, increasing domestic gas production and acquisition of shares in gas resources outside Poland are the key elements of Poland's gas security policy.

Under the Act of 16 February 2007 (amended in 2011), energy enterprises running a business of international gas trading and import are obliged to maintain compulsory gas stocks in storage installations connected to the gas system within the territory of Poland. From 1 October 2012, these stocks must amount to 30 days of imports.

These mandatory stocks of natural gas must be stored in installations that enable delivery of the entire inventory of these stocks to the gas transmission system within 40 days. The mandatory gas stocks in Poland are commingled with commercial stocks. The amount of mandatory gas stocks is reviewed by the president of the Energy Regulatory

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Office on the basis of transport forecast for the nearest year. The costs incurred by enterprises/importers to fulfil the obligation are considered as the justified costs of their operations and could be included in tariffs. Compulsory stocks of natural gas may be held in storage facilities located outside the territory of Poland – in other EU countries.

Emergency response measures

Compulsory gas stocks are held at the disposal of the Minister of Economy. These stocks may be released by the operators of the gas transmission system or of the consolidated gas systems immediately after receiving permission from the Minister of Economy.

In case disruptions occur to the gas transmission system in the supply of natural gas, the following procedures can be taken in phases.

In Phase I of a gas emergency, trade enterprises and importers will secure additional supplies of natural gas from other sources on a commercial basis, and will reduce gas supply to major consumers according to the agreements with them. PGNiG has some contracts with natural gas consumers, which allows it to impose restrictions for commercial reasons. Such interruptible contracts require notification of the client at least 8 hours in advance, before the agreed restriction level is implemented.

If the TSO assesses that the measures introduced in Phase I are insufficient to eliminate the threat to the security of the natural gas supply in Poland, the Minister of Economy will decide on the use of compulsory stocks (Phase II). OGP GAZ-SYSTEM (TSO) is responsible for conducting the withdrawal of compulsory gas stocks, in co-ordination with the SSO, PGNiG.

If the measures taken in Phases I and II do not restore the state of Poland's natural gas security, the TSO will notify the Minister of Economy of the need to impose restrictions on the use of natural gas (Phase III). According to the regulation of the Council of Ministers of 19 September 2007, households and other customers with total contracted capacity from the exit point of less than 417 m^3/h are not subject to restrictions. The restrictions will be imposed on the basis of plans, which are elaborated by TSO, DSOs and enterprises fulfilling the role of network operators, and need to be approved by the president of the Energy Regulation Office.

If the response measures of Phases I to III turn out to be insufficient, the Council of Ministers can include commercial stocks being held in storage facilities throughout the country into the compulsory stocks of natural gas (Phase IV).

The Polish government has no legal authority or policy to promote fuel switching away from natural gas in an emergency. Gas-fired power plants are not legally required to hold backup fuel stocks on site. However, the level of energy produced from natural gas is minimal.

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Portugal

Key data

Table 4.22.1 Key Oil Data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	0.0	0.0	0.0	0.2	0.9	0.4	1.0
Demand (kb/d)	251.0	332.7	336.9	274.4	260.5	234.0	219.1
Motor gasoline	31.7	49.0	41.9	32.1	28.9	26.1	-
Gas/diesel oil	54.2	101.2	115.0	113.6	105.4	95.1	-
Residual fuel oil	79.1	68.9	63.7	27.3	28.7	26.7	-
Others	85.9	113.6	116.3	101.4	97.5	86.2	-
Net imports (kb/d)	251.0	332.7	336.9	274.2	259.6	233.6	218.1
Import dependency (%)	100	100	100	99.9	99.7	99.8	99.5
Refining capacity (kb/d)	313.0	304.3	304.2	310.3	310.3	310.3	-
Oil in TPES (%)**	64	61	59	50	47	43	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.22.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	0	0	0	0	0	0	0
Demand (mcm/y)	0	2 280	4 258	5 140	5 184	4 629	4 482
Transformation	0	1 384	2 650	3 178	3 148		-
Industry	0	744	1 096	1 206	1 320		-
Residential	0	83	229	342	295		-
Others	0	69	283	414	421		-
Net imports (mcm/y)	0	2 280	4 258	5 140	5 184	4 629	4 482
Import dependency (%)	0	100	100	100	100	100	100
Natural gas in TPES (%)	0	8	14	19	19	18	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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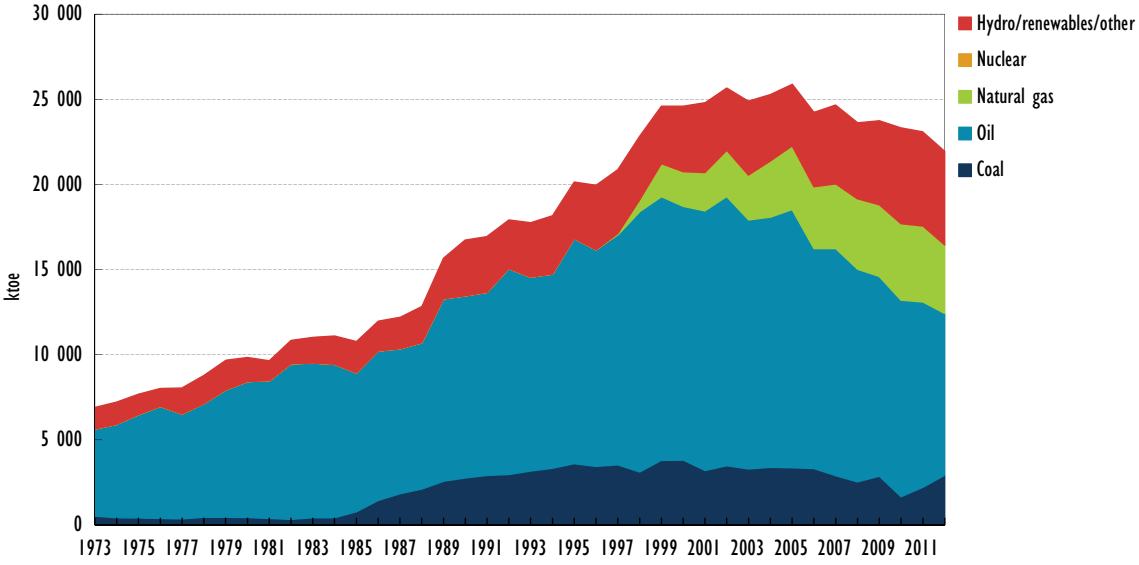
Figure 4.22.1 Total primary energy source (TPES) trend, 1973-2012



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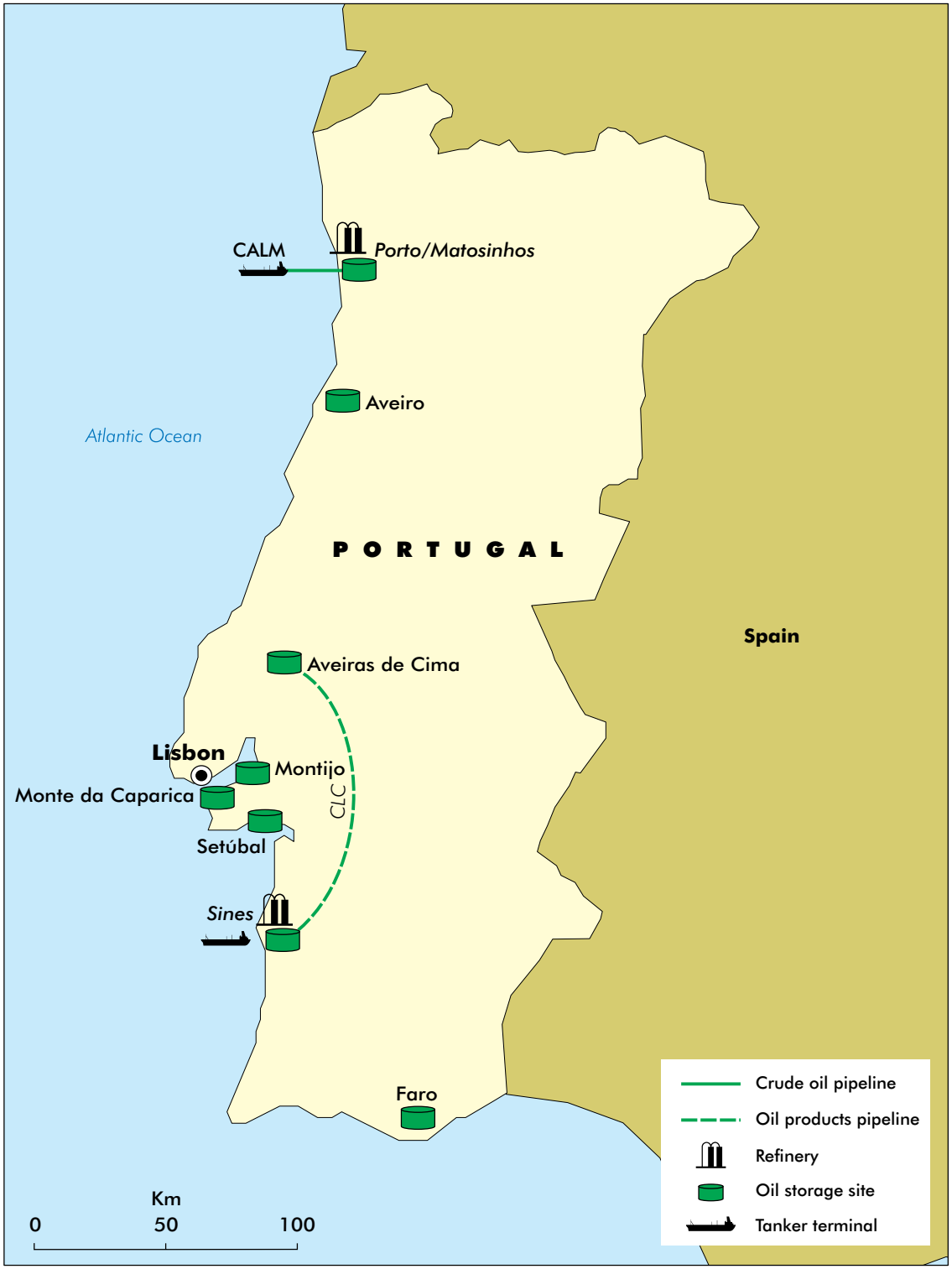
Map 4.22.1 Oil infrastructure of Portugal



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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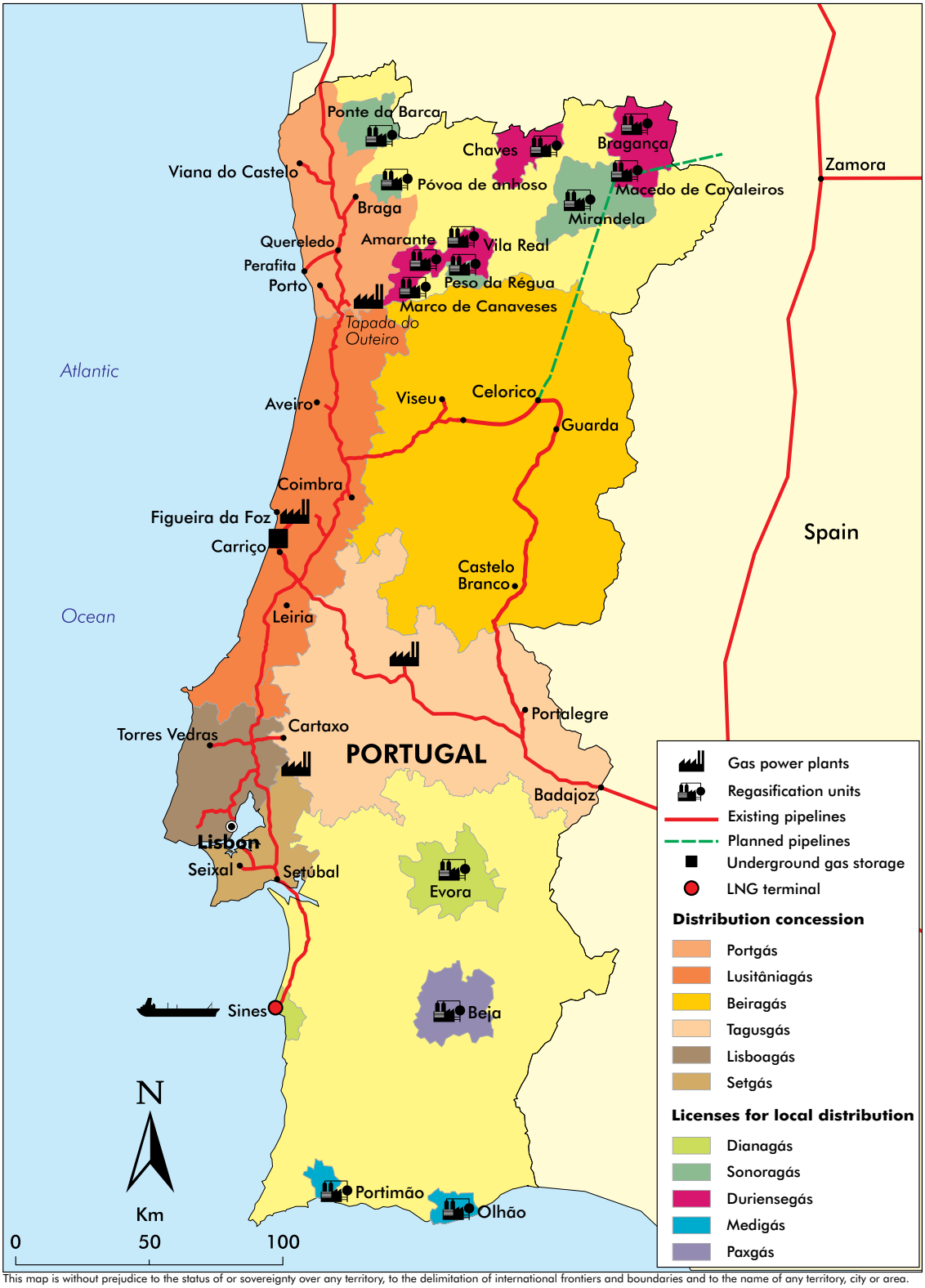
Map 4.22.2 Gas infrastructure of Portugal



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Country overview

Oil has been a dominant energy source, representing some 43% of Portugal's total primary energy supply (TPES) in 2012. Oil demand in Portugal has been declining from its peak of 343 thousand barrels per day (kb/d) in 2002. In 2012 total oil demand averaged 234 kb/d.

With very limited indigenous oil production, Portugal is almost fully dependent on imports. Portugal has well diversified crude oil supply sources. By country, Angola was the largest oil supplier in 2012 (23% of total crude oil import), followed by Brazil and Kazakhstan (11%), Algeria (10%) and Saudi Arabia (9%).

Portugal meets its stockholding obligation to the International Energy Agency (IEA) and the European Union by holding agency stocks and placing a minimum stockholding obligation on industry. Oil industry operators hold two-thirds of the EU obligation (i.e. 60 days of consumption), while the stockholding agency Entidade Gestora de Reservas Estratégicas de Produtos Petroliferos (EGREP) is obliged to hold the remaining one-third of the EU obligation and cover the difference between total EU and IEA stock obligations. Operators and EGREP are also required to hold reserves of 20 and 10 days of liquefied petroleum gas (LPG), respectively. Small operators may delegate their obligation to EGREP under certain conditions.

Portugal held some 24.3 mb of oil stocks (7.9 mb of agency stocks and 16.5 mb of industry stocks) at the end of April 2013. Around 37% of total stocks were held in the form of crude oil, followed by middle distillates (30%).

The use of stocks held by EGREP and by industry is central to Portugal's emergency response policy. Portugal has a well-defined stock release procedure for public stocks stored in the country. The Directorate-General for Energy and Geology (DGEG) in the Ministry of Environment, Spatial Planning and Energy is the core body of the Portuguese national emergency strategy organisation (NESO).

Demand for natural gas, which was only introduced in the past decade, has steadily increased and reached 5.2 bcm in 2011; it then decreased to 4.6 billion cubic metres (bcm), or 13 million cubic metres per day (mcm/d) in 2012. In the same year, some 51% of natural gas was imported in the form of liquefied natural gas (LNG) mainly from Nigeria; the rest was supplied from Algeria through the Mahgreb-Europe Gas Pipeline.

Portugal has a policy that mandatory security gas reserves must be provided by market suppliers, namely, those agents who import the gas that is supplied to the country. The minimum quantity of stocks of natural gas needs to more than the necessary level to ensure the consumption of protected consumers and to meet the consumption of non-interruptible power plants.

Release of compulsory gas stocks is decided by the minister responsible for energy. No automatic triggers exist under the current relevant laws. The drawdown capacity of the underground storage facilities in Carriço is 7.2 mcm/d, while the nominal drawdown capacity of LNG storage plants in Sines Terminal is 27 mcm/d.

Oil

Market features and key issues

Domestic oil production

With very little indigenous crude production, the country relies on imports to meet all its domestic crude oil requirements.

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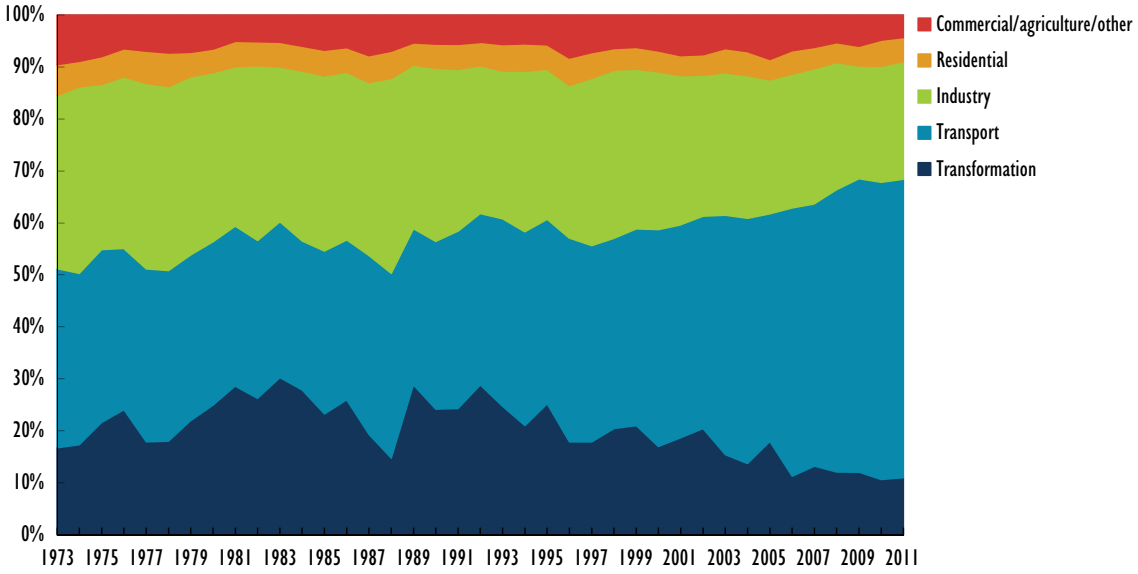
Oil demand

Oil demand in Portugal has been declining from its peak of 343 kb/d in 2002. In 2012 total oil demand averaged 234 kb/d. The annual compound decrease rate is 3% to 4% from the peak oil demand in 2002.

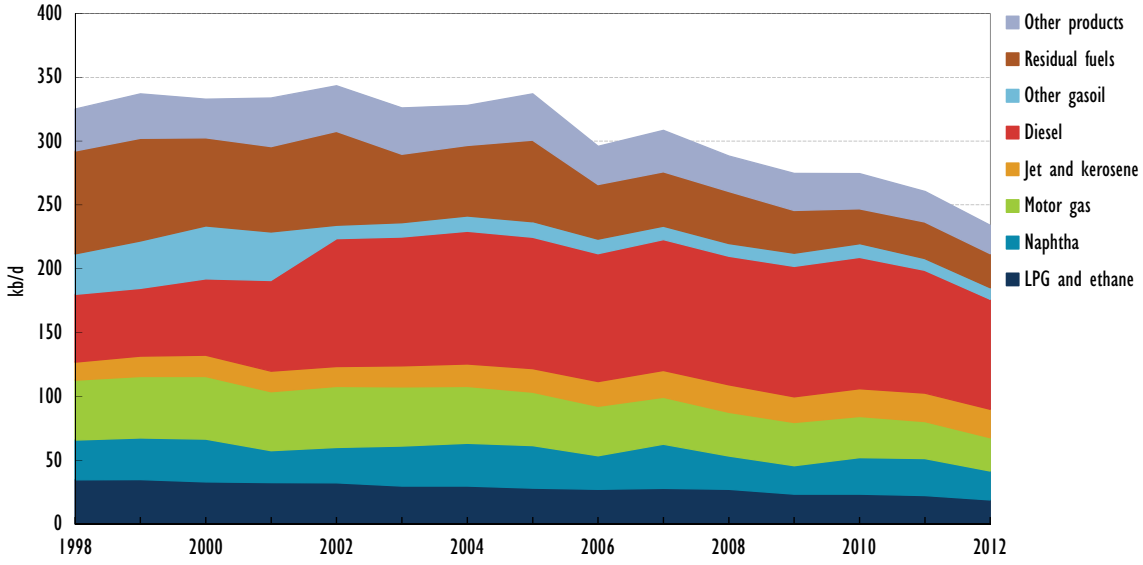
Oil demand in the transport sector has risen significantly, standing at 57% of total consumption in 2011. In the 2000s, the increase of demand in the transport sector had been supported by sharp growth in demand for diesel.

Figure 4.22.2 Oil consumption by sector, 1973-2011



However, diesel demand has also dropped from 103 kb/d in 2010 to 86 kb/d in 2012 owing to the economic recession. Motor gasoline demand has decreased by over 40% during the last decade. Demand for fuel oils has decreased more significantly by over 50% during the same period.

Figure 4.22.3 Oil demand by product, 1998-2012



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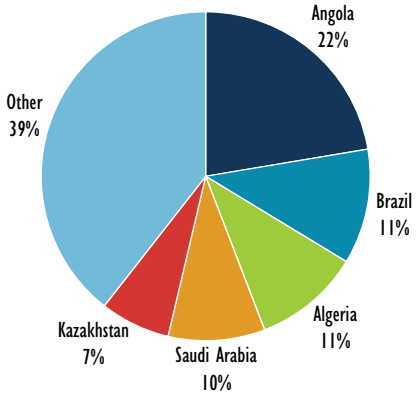
Imports/exports and import dependency

In 2012 Portugal imported 290 kb/d, consisting of 227 kb/d of crude oil and 63 kb/d of refined products. Portugal has well diversified crude oil supply sources. By country, Angola was the largest oil supplier in 2012 (23% of total crude oil import), followed by Brazil and Kazakhstan (11%), Algeria (10%) and Saudi Arabia (9%).

Figure 4.22.4 Crude oil imports by origin, 2012



In the same year Portugal exported 76.2 kb/d of refined products. Its main export product was fuel oil (29.6 kb/d).

Oil company operations

The most important player in the Portuguese oil market is Galp Energia. It operates the two oil refineries in the country and has a strong position in the domestic oil market. Through its oil retail and wholesale divisions, Galp Energia, is directly involved in all sectors of the market. The retail gasoline market in mainland Portugal is highly concentrated, with the four main operators, Galp, Repsol, Cepsa and BP, accounting for over 67% of outlets in 2012. A number of small independent players are also involved in the retail market, including the major supermarket chains (21%).

Oil supply infrastructure

Refining

The two refineries owned by Galp Energia have a combined crude oil processing capacity of 330 kb/d. With a refining capacity of around 220 kb/d, Sines refinery is the main refinery in Portugal, accounting for almost 70% of the country's total refining capacity. Sines Refinery is one of the largest refineries on the Iberian Peninsula. The Matosinhos refinery, located on the country's northwest coast, has an annual refining capacity of some 110 kb/d. The Matosinhos refinery is a hydroskimming refinery with vacuum distillation.

In 2012, total refinery gross output was 240 kb/d. The refineries' total product yield was Gas/diesel oil (35%), residual fuel oil (20%) and gasoline (17%).

Galp Energia has upgraded Sines and Matosinhos refineries, aiming to adjust their production profile to the needs of the Iberian market, where diesel is in short supply, by maximising the annual production of diesel and by reducing the share of fuel oil production which exceeds domestic demand.

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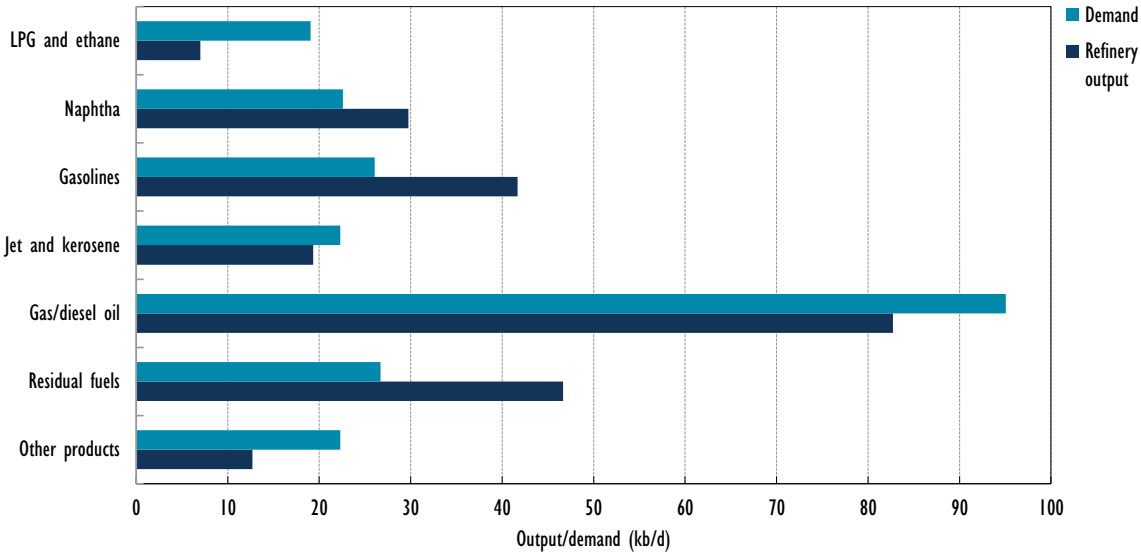
Figure 4.22.5 Refinery output vs. demand, 2012



This upgrade project has also enabled greater flexibility of the facilities, allowing for adjustments to the production profiles for a faster response to changes in demand for refined products. The procedural reconfiguration has secured the operational complementarities of both refineries and created a fully integrated refining system with product exchange.

Ports and pipelines

Lack of cross-border pipelines has meant that nearly all imports of crude oil pass through the two major ports on the Atlantic Ocean. The oil terminal at Port Sines, which is operational throughout the year, has the capacity to unload around 64 kb/h and supports very large crude carriers (VLCCs). Because of difficult weather conditions in winter, the oil terminal at the Port of Leixões does not receive oil tankers during 50 to 80 days per year. To solve this problem, Petrogal installed a single point mooring (SPM) terminal (a buoy) at sea, some 3 km offshore which is connected to the Petrogal Refinery by an underwater pipeline. The SPM has an unloading capacity of some 50 kb/hour.

In addition to the two major ports, smaller ports and terminals such as at Aveiro, Lisbon and Setubal, as well as in the Madeira and Azores autonomous regions, can be used for import and export of refined products, which enhances flexibility of response during emergencies.

Oil products are distributed to inland areas through the Companhia Logística de Combustíveis (CLC) pipeline, a multi-product pipeline between the Sines refinery and the tank farm at Aveiras (45 km north of Lisbon). The CLC pipeline has the capacity to carry some 80 kb/d of seven different products, in sequence and by cycles. From the tank farm, oil products are transported by truck. There is also a 4 km jet fuel pipeline running from the Porto refinery to the international Porto airport of Sá Carneiro (serving northern Portugal). This jet fuel pipeline, with a capacity of 13 kb/d, is operated by Petrogal.

Storage capacity

Portugal's total storage capacity was 6.6 mcm (some 42 mb) as of August 2013. Storage capacity of crude oil, diesel and gasoline accounted for 31%, 23% and 7% of the total capacity respectively. Approximately 80% of the total capacity was located at the two refineries, namely Sines refinery (3.4 mcm) and Porto refinery (1.9 mcm).

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In August 2013, almost 84% of the total storage capacity (5.5 mcm) was owned by Galp Energia. Galp Energia held all the storage capacities for crude oil in the country. The logistical and tanking joint venture company CLC owned some 0.35 mcm, representing around 5% of the total storage capacity The remaining portions were held by Repsol (2.2%), LBC (2.0%), Prio (1.2%), OZ (1.0%), Termitrena (1.0%), Cepsa (0.9%), ETC (0.8%), BP (0.1%) and other small operators (1.8%).

Decision-making structure

The DGEG within the Ministry of Environment, Spatial Planning and Energy is the core body of the Portuguese NESO structure. The DGEG is responsible for ensuring planning of supply, production and use of energy resources, supporting the minister responsible for energy in making decisions, particularly in crisis or emergency situations, within the National System of Civil Emergency Planning and in close collaboration with industry representatives.

The minister responsible for energy has the authority to decide whether the country will accept an IEA initial assessment or not, and which response measures to take in order to participate in an IEA collective action.

Stocks

Stockholding structure

Portugal meets its minimum stockholding obligation to the IEA and the European Union by holding agency stocks and placing a minimum stockholding obligation on industry. Oil industry operators should hold a maximum two-thirds of the EU obligation, while EGREP, is obliged to hold, at a minimum, the remaining one-third of the EU obligation and to cover the difference between total EU and IEA stock obligations. The industry and EGREP are also required to hold reserves of 20 and 10 days of LPG respectively. The stockholding agency EGREP is a public corporation under the supervision of both the Ministry of Finance and the ministry responsible for energy. EGREP must own at least 25% of its stocks.

The minister responsible for energy has three main responsibilities: co-ordinating the allocation and sale of stocks during an energy supply crisis; authorising the sale of surplus reserves held by EGREP (if such an occasion should arise); and approving the amounts companies will pay to EGREP. The minister can authorise a given entity to agree with EGREP to delegate the entity's total stock obligation to EGREP. The applicant's inability to maintain the required stocks should be justified by reasons beyond its control. Fulfilling all the obligation through EGREP has been used by small operators entering the market so that the need for storage capacity does not create a barrier to entry or competition.

Crude or products

At the end of April 2013, Portugal held some 24.3 mb of oil stocks (7.9 mb of agency stocks and 16.5 mb of industry stocks), equal to 116 days of 2012 net imports. Around 37% of total stocks were held in the form of crude oil, followed by middle distillates (30%).

At least one-third of the individual stock obligations of companies (including EGREP) are required to be held as products. This applies separately to each category of qualifying products; volumes to be held are calculated by product category, not by individual product. Semi-finished products are counted as finished product within the appropriate qualifying product category. If an obliged stockholder (including EGREP) wishes to hold crude oil in place of part of its product stock obligation, the product yield is the one forecast annually by the country's refineries and formally conveyed to the DGEG.

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Location and availability

The DGEG can authorise individual stockholders to hold compulsory stocks in another EU member country, provided the stockholder is able to certify that it is unable to secure competitive access to sufficient Portuguese storage capacity to fulfil its obligation. Portugal has bilateral agreements with Germany, the Netherlands and Spain.

Individual supplying companies may not hold more than 10% of their obligation abroad and there is also a minimum quantity (20 kilotonnes). In total, no more than 20% of the country's overall obligation may be held abroad; this includes volumes held as stock tickets. These criteria effectively allow EGREP to hold more than 20% of its obligations abroad. To ensure adequate stock rotation, compulsory stocks are mostly commingled with operational stocks.

Monitoring and non-compliance

Tanks used for compulsory stocks must be approved by the DGEG. In turn, the DGEG maintains updated lists of approved tanks, thereby allowing clear identification of compulsory stocks locations. If one company holds stocks on behalf of another company, both the quantities and the location of the stocks must be reported to the authorities to facilitate cross-checking of stocks reporting and physical inspections.

The DGEG has the authority to issue fines to companies found to be non-compliant with stockholding obligations. The amount of the fines is graduated in proportion to the gravity of the infringement, or for repeat offences.

Stock drawdown and timeframe

The minister responsible for energy has the authority to release EGREP emergency stocks or to allow the reduction of stocks held by industry.

There is a clear procedure for the drawdown and sale of agency stocks that are stored in Portuguese facilities. Industry operators shall have a right of first refusal over stocks held by EGREP, in proportion to their share in the financing of such stocks (i.e. according to their respective market shares). The following steps would be taken for sales of agency stocks held domestically:

- After the Government notifies the volumes to be released, EGREP invites operators to express their interest in receiving stocks from the strategic reserves
- Operators make their decisions known in writing within 72 hours
- GALP (the company which stores stocks on behalf of EGREP) is notified by EGREP of volumes to be delivered to each operator
- After receipt of EGREP's notification, GALP starts making volumes available in 8 days for diesel, 5 days for other products and 15 days for crude oil
- Unless stock loans are chosen as the best release mechanism, release prices are to be determined as the average of the previous week's Platt's quotations, so as to avoid arbitrage between EGREP and the national refiner
- Volumes not taken up by operators can be re-offered.

In the case of drawdown of crude oil stocks which EGREP holds in Germany, a different strategy would be taken according to the emergency situation. Sale by tender on the global market as part of an IEA co-ordinated action is one option. Swapping or processing of the stored crude oil at nearby refineries could be another option. Repatriation of the crude oil is regarded as the last option. As for industry stocks, Decree Law 114/2001 stipulates that lowering the legal level of industry compulsory stocks requires an

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order from the minister responsible for energy; this would be followed by the DGEG's notification to oil companies.

Financing and fees

EGREP is financed by levies charged to operators with compulsory stock obligations. The fees are to be paid according to the volumes operators sell in the domestic market. These fees are as follows: EUR 8.30/t for gasoline (Category A); EUR 5.00/t for gasoil (Category B); EUR 6.45/t for fuel oil (Category C); and EUR 2.33 /t for LPG (Category D).

Other measures

Demand restraint

Portugal's demand restraint measures were legally formalised by the Decree Law 114/2001, which specifies a set of potential measures, both persuasive and compulsory. Persuasive measures designed to stimulate the population to reduce oil consumption include media awareness campaigns, publication of leaflets and explanatory guides, display of posters in public locations and direct action by state or public administration agents.

If further action is required, the following compulsory measures are envisaged:

- restrictions on the use of passenger cars (e.g. driving bans, interdiction of motor sport events, reduction of speed limits or requirements concerning occupancy)
- restrictions on under-utilised public or commercial transportation
- restrictions on the use of energy-consuming equipment (e.g. limiting operating times and lighting levels, reducing use of heating and cooling in public or private buildings)
- imposition of operating rules for energy-consuming equipment
- enforcement of fuel switching.

The law of 2001 also allows for measures that indirectly promote energy saving, such as the introduction of flexible working hours or an increase in energy tariffs and charges.

Fuel switching

Though fuel switching is clearly stated as an available emergency response measure in Decree Law 114/2001, no specific policy has been developed. Fuel-switching capacity for oil consumers is very limited in the short term.

Other

With no significant indigenous oil production, surge production of oil is not considered an emergency response measure in Portugal.

Gas

Market features and key issues

Gas production and reserves

Portugal has no significant proven reserves of natural gas. There is no indigenous gas production, and therefore the country relies on imports to meet all its domestic gas requirements.

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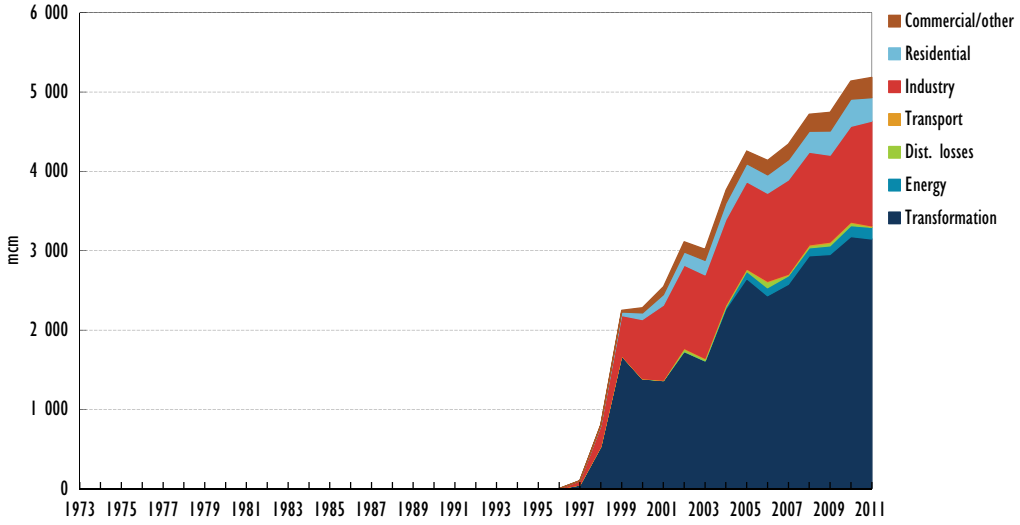
Gas demand

Supply of natural gas to the Portuguese market began in 1997. Since then, natural gas demand has steadily increased to 5.2 bcm in 2011 and then in 2012 decreased to 4.6 bcm (around 13 mcm/d on average).

Figure 4.22.6 Natural gas consumption by sector, 1973-2011

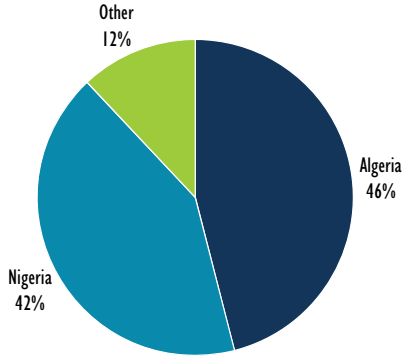


The seasonality of natural gas consumption in Portugal is not as evident as observed in most European countries. The reason for this is the fact that Portugal has a mild climate and that natural gas is not used extensively in the housing sector for heating. The transformation sector accounted for over 60% of natural gas consumption in 2011. In 2012 the daily peak demand was 206.97 GWh/d (roughly 17.4 mcm/d).

Gas import dependency

Because of the absence of natural gas production, Portuguese gas demand is entirely supplied by imports. There are two main gas suppliers: Algeria (46% of the 2012 total) and Nigeria (42%). The share of LNG supply to the Portuguese market was 46% and the remaining 54% corresponded to natural gas pipeline imports through the two existing international pipelines connecting the Spanish gas system. Most of the natural gas imported through the pipelines is originally from Algeria, through the Euro Maghreb Pipeline system. The existing long-term supply contracts with take-or-pay clauses represented roughly 88% of all imports (46% from Sonatrach, an Algerian state-owned company, and 42% from Nigeria LNG Ltd).

Figure 4.22.7 Natural gas imports by source, 2012



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Gas company operations

Galp Energia is the most important natural gas supplier in the Portuguese market, holding a portfolio of long-term contracts which amounts to nearly 6 bcm per year. One contract until 2020 is for natural gas with Sonatrach, an Algerian state-owned company, and there are three others for LNG signed with Nigeria LNG Ltd. up to 2026.

Gas supply infrastructure

Ports and pipelines

Natural gas is fed into the national gas transmission network through two main entry points: Campo Maior, located on the eastern border with Spain, and the Sines LNG Terminal located on the Atlantic coast and about 150 km south of Lisbon. In the transmission system, the maximum technical capacity at the entry point of Campo Maior is 3.5 billon cubic metres per year (bcm/y), while it is 5.3 bcm/y at the entry point of Sines, which is planning expansion up to roughly 8 bcm/y. This capacity expansion will include a new compressor station in Carregado to the northeast of Lisbon. In addition, the gas pipeline crossing point at Valença do Minho, which is located on the northern border with Spain, can occasionally receive natural gas from its neighbour with an entry capacity of about 0.7 bcm/y.

A project to develop the third interconnection pipeline between the Portuguese and the Spanish transmission systems aims to enhance Portugal's natural gas accessibility and market competition. This will also fulfil compliance with the N-1 standard provided in the relative European regulation (Regulation 994/2010) from 2018 onwards.

In the Sines Terminal, LNG is offloaded and pumped into temporary storage tanks where it remains until an order is issued by the owner of the gas for regasification prior to delivery into the national gas transmission network.

The Portuguese National Natural Gas Transmission Network (RNTGN) consists of a main trunk line and branch lines which totalled 1 298 km at the end of 2012. The RNTGN has two interconnections with Spain at Campo Maior in the east and Valença do Minho in the north, and interfaces the LNG import terminal of Sines and the underground natural gas storage facility of Carriço, located in the region of Pombal.

Storage

Portugal has both underground storage facilities and LNG tanks for storing natural gas. At the end of 2012, the Carriço underground storage had four salt caverns in operation, with a maximum working volume of 178 mcm of natural gas, through two concessionaires (REN Armazenagem and Transgás Armazenagem). The gas station is operated by REN Armazenagem, and it has a nominal withdrawal capacity of 7.2 mcm/d and an injection capacity up to 2.4 mcm/d. The country also plans to commercialise four caverns until 2022. The Sines LNG Terminal, operated by REN Atlântico, has three tanks with a combined storage capacity of 390 000 m^3 of LNG (roughly 240 mcm of natural gas). The plant's send-out capacity is up to 27 mcm/d of natural gas.

Emergency policy

The amended Decree Law 140/2006, together with Decree Law 231/2012, stipulates that the minister in charge of energy can define priority rules in case of an emergency, taking into consideration a stable gas supply for household consumers, health services, safety services and other consumers highly dependent on gas.

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As the natural gas infrastructure in Portugal is new and its transmission capacity is higher than the present requirements, so far there has been no congestion. The regulatory authority has established competitive bidding as the rule for capacity allocation needs to be in line with new European network codes under preparation by the European Commission. This will eventually lead to demand-side management for client portfolio management from the shippers, if and when congestion arises in the gas system.

Emergency response measures

Under amended Decree Law 140/2006, together with Decree Law 231/2012, mandatory gas reserves must be provided by market players who are responsible for supplying natural gas to the final consumers. They have a mandate to hold gas reserves corresponding to the consumption of protected customers such as residential, tertiary and small industry. The amount is up to 20% of the country's total gas demand over 30 days of unusually high demand (1 in 20 winters). Those market suppliers are also obliged to hold gas reserves corresponding to the consumption of non-dual-fired CCGTs for 30 days of unusual high gas demand for electricity generation. Every month market players are notified of consumption figures: the number of average consumption days vis-à-vis demand in the preceding 12 months. As of September 2013, the mandatory gas reserves, which are in line with the stipulations of EC Regulation 994/210, amount to roughly 18 days of average consumption of the whole market in the preceding 12 months.

The gas inventories that may be counted for the purpose of mandatory security reserves are the combined existing stocks of each responsible market agent in underground storage, in LNG storage and on LNG carriers with fixed port destinations in Portugal, with an estimated time of arrival of within three days.

REN Gasodutos is responsible for the global systemic management of the Portuguese natural gas system operating the high-pressure infrastructures. It is also assigned to monitor the compliance of market players in maintaining mandatory gas reserves. These obligations are monitored and reported to the DGEG on a monthly and quarterly basis.

The mandatory gas reserves in Portugal are commingled with commercial stocks. The average stock level of mandatory gas reserves in 2012 was estimated to be around 175 mcm, which is equivalent to a volume of some 15 days of import in the same year. However, as indicated above, some of this volume was in ships underway from Nigeria to Portugal. The volume of commercial stocks stored in underground storage and the LNG terminal depends on the market players' commercial policy, but can vary between nearly zero (just before unloading an LNG tanker) and about 225 mcm when stocks are at their maximum and there is no LNG tanker with an estimated time of arrival within 3 days.

Release of compulsory gas stocks is decided by the minister responsible for energy under the conditions established by the legislation. No automatic triggers exist under the relevant laws. The withdrawal capacity of the underground storage facilities in Carriço is 7.2 mcm/d, while the send-out capacity of LNG storage plants in Sines Terminal is up to 27 mcm/d of natural gas.

The administration has no demand restraint programme in place for rapid and short-term reduction of gas consumption during a gas supply disruption.

Fuel-switching capacity for gas users is limited in Portugal. In the case of electricity generation, the CCGT of Turbogás (990 MW) and the CCGT of Lares (830 MW) have dual-fuel fire capabilities for natural gas and petroleum distillates. Those dual-fuel power plants, however, are not required to hold any diesel stocks as no legal requirement exists for increasing fuel-switching capability.

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The Slovak Republic

Key data

Table 4.23.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	0.0	1.2	7.3	5.1	4.6	5.0	6.0
Demand (kb/d)	106.7	66.8	78.5	83.7	81.9	70.3	73.3
Motor gasoline	10.9	13.9	14.9	14.4	13.6	11.9	-
Gas/diesel oil	26.7	17.1	22.9	32.5	31.8	29.5	-
Residual fuel oil	27.5	3.4	6.1	6.4	4.6	4.2	-
Others	41.7	32.3	34.7	30.4	31.8	24.8	-
Net imports (kb/d)	106.7	65.6	71.2	78.6	77.3	65.3	67.3
Import dependency (%)	100	98.2	90.7	93.9	94.4	92.9	92
Refining capacity (kb/d)	0.0	115.0	115.0	128.5	128.5	128.5	-
Oil in TPES (%)**	22	16	18	20	20	20	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.23.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	438	173	147	104	121	150	91
Demand (mcm/y)	6 363	7 136	7 227	6 099	5 630	5 289	4 072
Transformation	1 277	1 758	1 733	1 389	1 433	0	-
Industry	1 668	1 379	1 660	1 338	1 593	0	-
Residential	1 364	2 030	1 734	1 623	1 424	0	-
Others	2 054	1 969	2 100	1 749	1 180	0	-
Net imports (mcm/y)	5 925	6 963	7 080	5 995	5 509	5 139	3 981
Import dependency (%)	93.1	97.6	98.0	98.3	97.9	97.2	98
Natural gas in TPES (%)	24	32	31	28	27	26	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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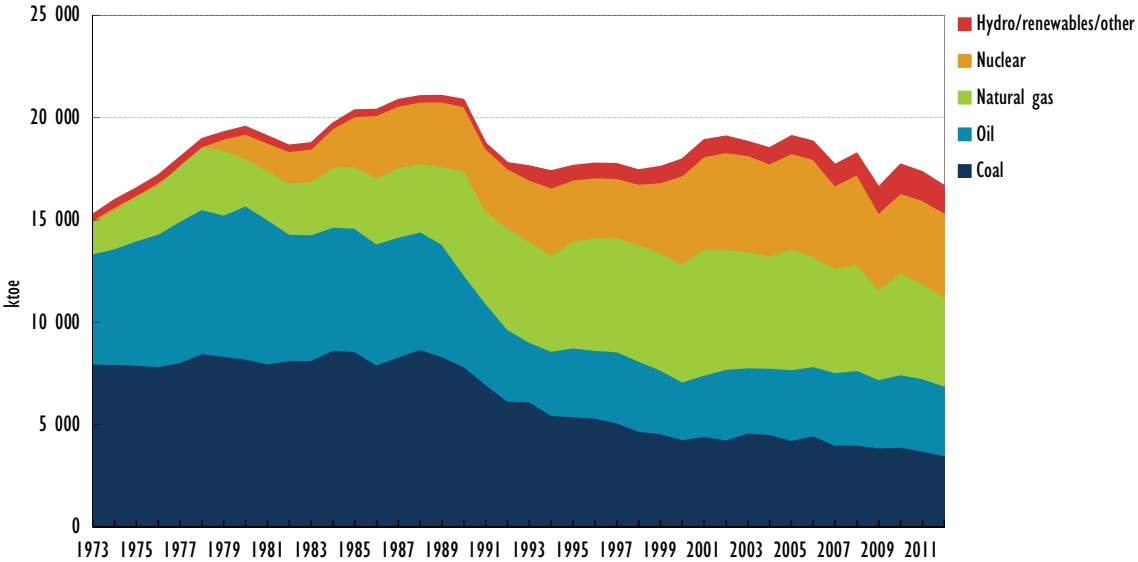
Figure 4.23.1 Total primary energy source (TPES) trend, 1973-2012



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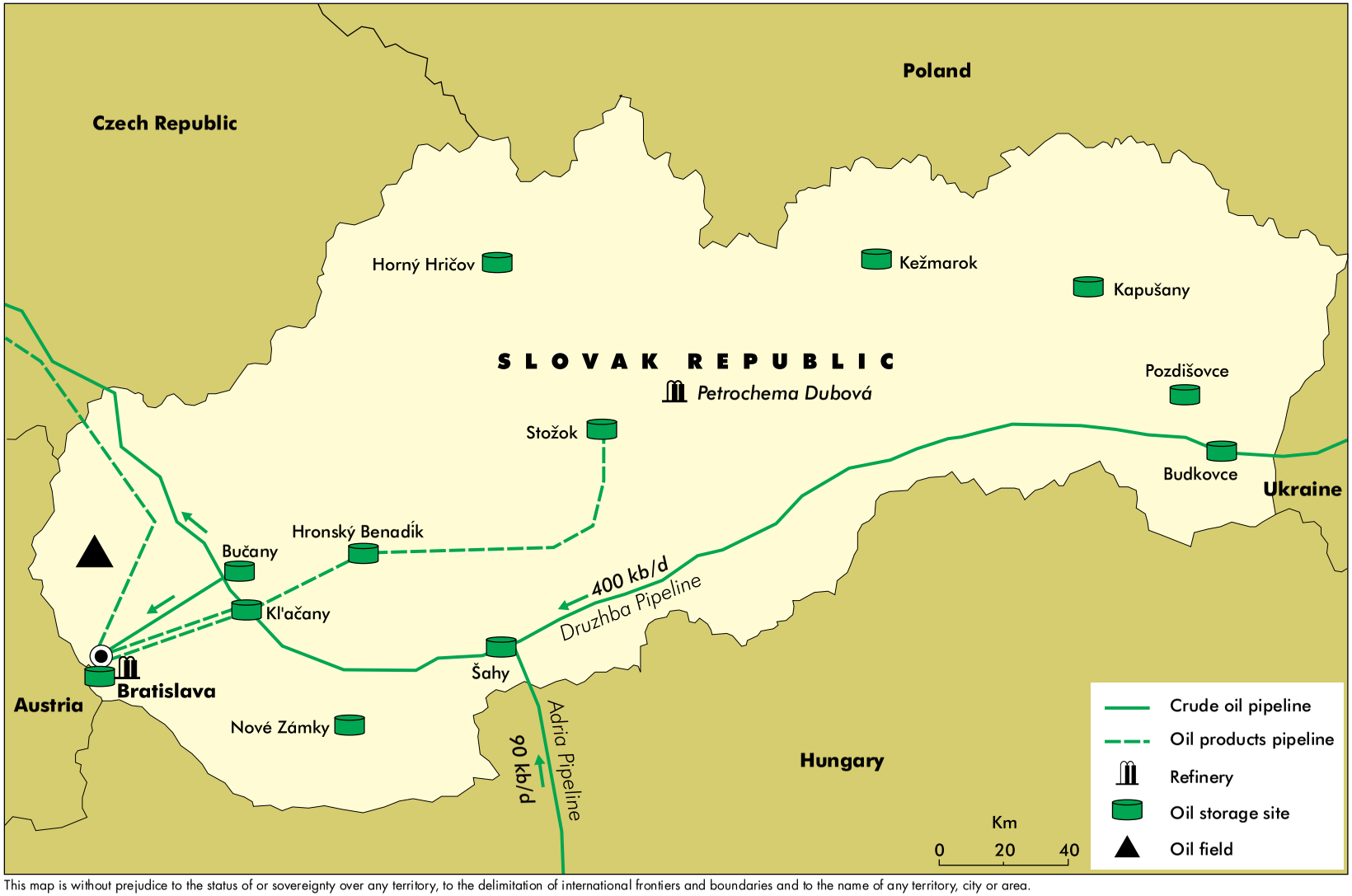
Map 4.23.1 Oil infrastructure of the Slovak Republic



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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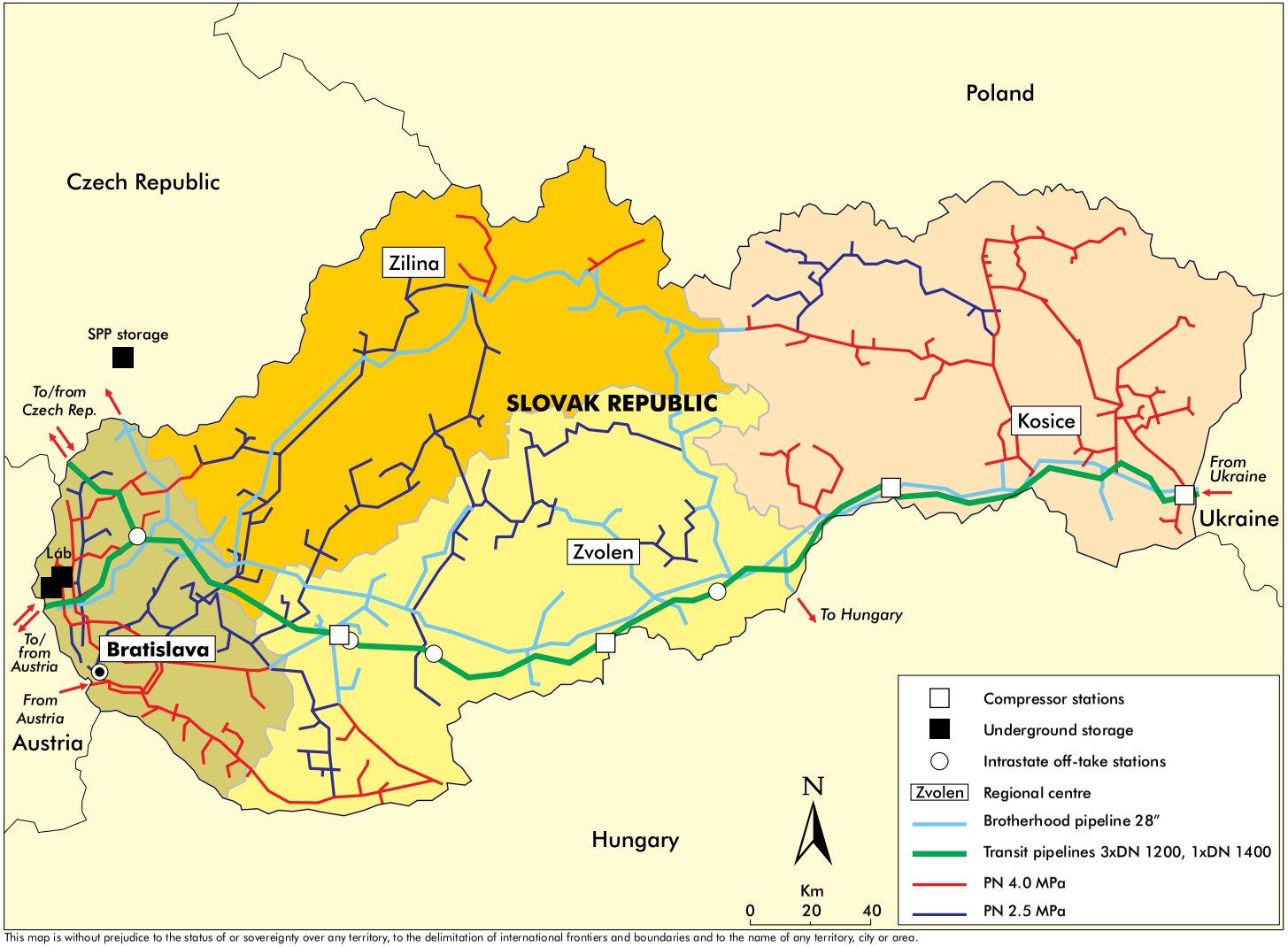
Map 4.23.2 Gas infrastructure of the Slovak Republic



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Country overview

Oil and natural gas represented 20% and 36%, respectively, of Slovakia's total primary energy supply (TPES) in 2012. While their share in the energy mix is not expected to change substantially over the next decade, demand for both fuels will continue to rise as total energy demand in the country grows.

Total Slovakian oil demand, some 70 thousand barrels per day (kb/d), is met almost entirely by Russian crude oil delivered via the Druzhba pipeline. This also the case for natural gas; all but a fraction of the country's 5.3 billion cubic metres (bcm) of gas demand is imported via pipeline from Russia.

Slovakia plays a key role in Europe's oil and natural gas supply chain. The country is a net exporter of refined oil products, providing significant quantities of product to neighbouring countries. Slovakia is also a major entry point for natural gas into the European Union, with transit volumes representing some 20% of total EU natural gas consumption.

Slovakia's primary response measure in an oil supply disruption is the drawdown of public oil stocks. The office which oversees the country's emergency reserves, the Administration of State Material Reserves (ASMR), is responsible for maintaining and implementing emergency measures in the event of an oil supply disruption. Emergency oil stocks are held by the Emergency Oil Stocks Agency (EOSA) and they cover Slovakia's entire stockholding obligation to the International Energy Agency (IEA) and the European Union. In an IEA co-ordinated action, the ASMR and EOSA would participate by releasing agency stocks – most likely in the form of loans to industry.

In the implementation of its natural gas emergency response policy, the Slovak government requires all suppliers operating on the domestic gas market to be able to meet standards of security of supply in circumstances of extreme weather conditions or the disruption of normal supplies. Natural gas suppliers must be able to guarantee their ability to meet average peak demand for 30 days, using measures such as the release of natural gas stocks, and backup deliveries from other countries.

Natural gas suppliers are obliged to inform the the government as to how they will comply with the security standard for the coming year. Following the experience of January 2009, Slovakia has also taken steps to improve the reversibility, and thus flexibility, of its gas transmission grid and to develop a new interconnection with Hungary's gas network.

Oil

Market features and key issues

Domestic oil production

Slovakia has no significant crude oil reserves – domestic oil production averaged about 5 thousand barrels per day (kb/d) in 2012. All producing fields are located in the west of the country, in the Gbely area of the Vienna basin. Crude production is expected to remain relatively flat in the coming years, increasing slightly to about 6 kb/d by 2018.

Oil demand

Oil demand in Slovakia totalled some 70.3 kb/d in 2012. The transport sector accounts for half of all oil used in Slovakia.

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Figure 4.23.2 Oil consumption by sector, 1973-2011

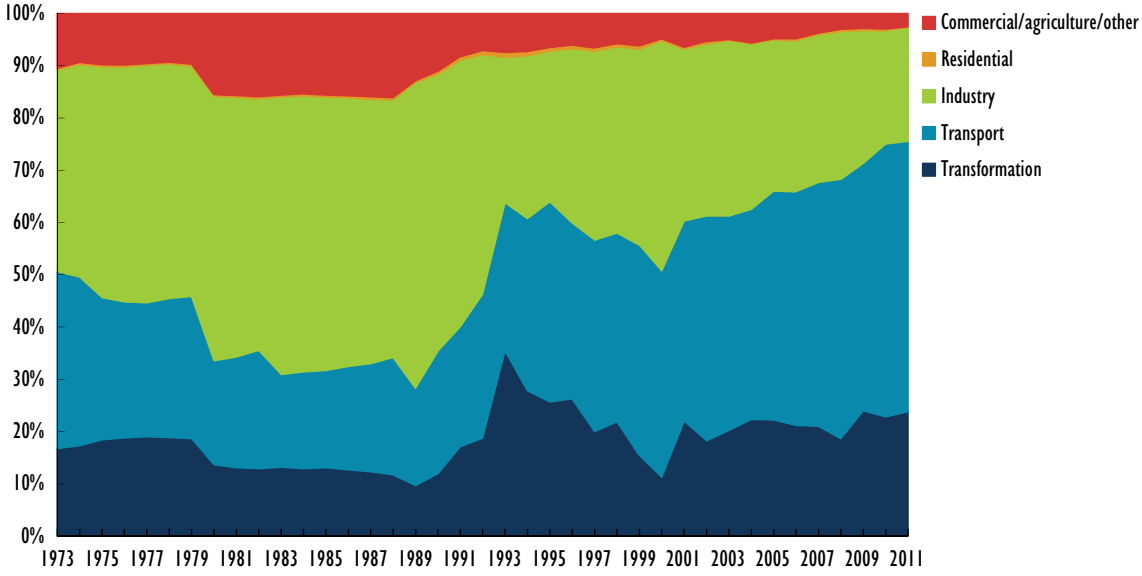
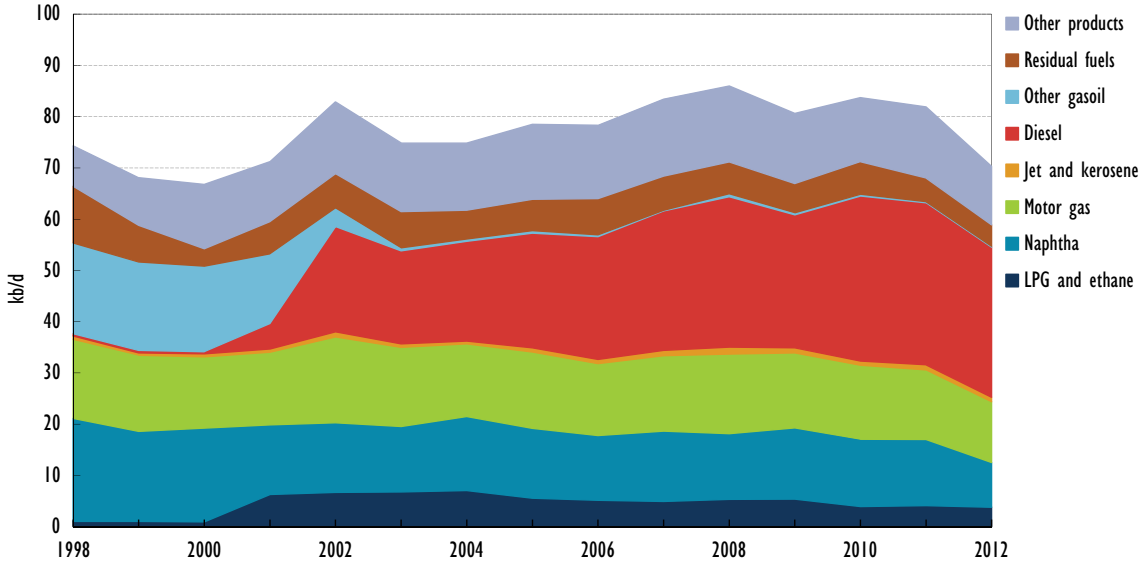


Figure 4.23.3 Oil demand by product, 1998-2012



The 2012 demand level marks a substantial decline from 2008, when oil demand peaked at 85.8 kb/d. In the period from 2005 to 2008 total oil demand grew by an average of 3% per year, primarily driven by growth in demand for transport diesel. Oil demand is expected to return to this trend as economic recovery gets underway. In 2012 diesel demand was 29 kb/d, representing roughly one-third of total oil demand and over 40% of all transport fuels consumed in the country. Automotive diesel has a price advantage for consumers because of a lower tax rate compared to gasoline.

Imports/exports and import dependency

Slovakia exports small amounts of domestically produced crude oil to Austria, while crude oil imports are entirely sourced from the Russian Federation through the Druzhba pipeline. Slovakia has a government-to-government agreement with Russia to supply up

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to 6 million tonnes per year (mt/y) – or 120 thousand barrels per day (kb/d) until the end of 2014. Crude oil imports from Russia averaged 126 kb/d in 2012.

Total output of finished products from domestic refining was nearly 130 kb/d in 2012, well in excess of domestic demand, allowing Slovakia to be a net exporter of finished products. In 2012, the country exported some 74 kb/d of refined products (mainly diesel), the bulk of which went to neighbouring countries, including the Czech Republic and Austria.

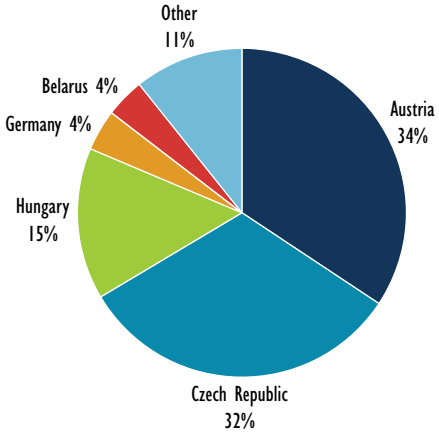
Oil company operations

The company Nafta produces domestic crude oil. Nafta is also involved in natural gas production and the building and operating of underground gas storage facilities.

Two companies, Transpetrol and Slovnaft, operate the bulk of the oil market infrastructure of Slovakia. Transpetrol is the sole operator of the country's crude pipeline network, and its operations also include crude storage for both its own customers and the ASMR. The company is fully state-owned, following a period of private ownership that ended in March 2009 when the government repurchased the remaining 49% of outstanding company shares.

Slovnaft, a member of the MOL group of Hungary, operates the country's refinery and product pipeline network. Its operations also include petrochemical processing and product storage as well as wholesale and retail distribution and product exports. Slovnaft holds a dominant position on the domestic market, supplying nearly two-thirds of all transport fuels distributed in the country. One-third of this amount is supplied through its own network of 209 petrol stations in the country. The other main oil companies operating in the Slovak retail and wholesale oil market include Eni Slovensko, Jurki Hayton, Lukoil Slovakia, MOL-Slovensko, OMV Slovensko, Shell Slovakia, Unipetrol Slovensko and Tesco stores.

Figure 4.23.4 Oil product imports by origin, 2012



Oil supply infrastructure

Refining

There is one operating refinery in Slovakia, Slovnaft's facility in Bratislava, which processed about 127 kb/d in 2012. A second refinery, Dubová, which had a capacity of 3 kb/d and processed mostly domestic crude supplied by non-pipeline routes, was closed in 2007.

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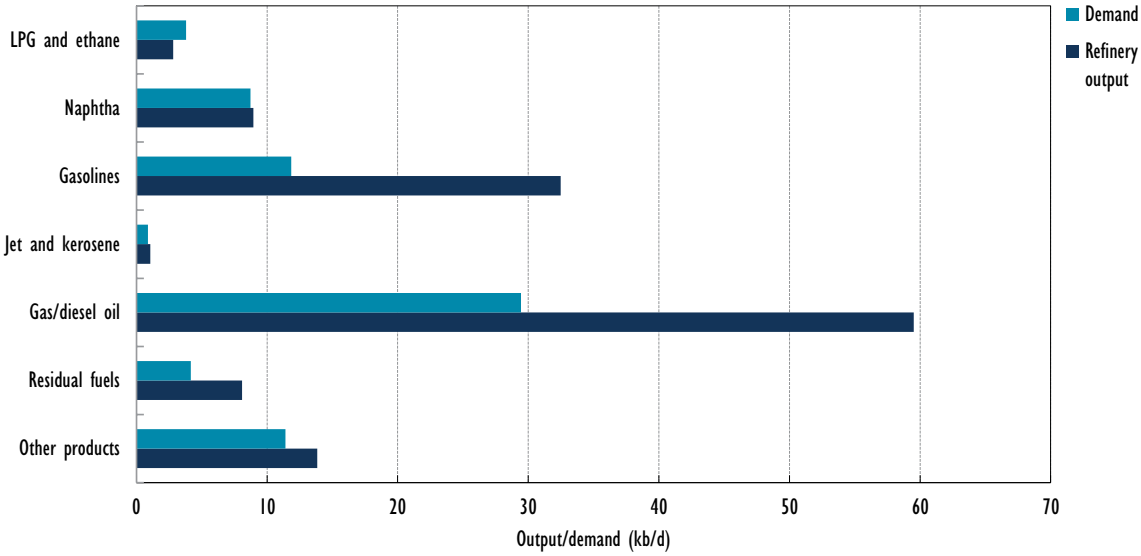
As total domestic refinery capacity exceeds oil demand in the country, Slovakia is a net exporter of refined product. The country's refineries produce a considerable surplus of output in all major oil product categories.

Figure 4.23.5 Refining output vs. demand, 2012



Pipelines

Slovnaft operates an oil products pipeline network that connects its Bratislava refinery to three key product terminals that hold ASMR public stocks. The pipeline system is used by Slovnaft for commercial purposes and connects to the Czech Republic's oil pipeline network. The network has a maximum transport capacity of 240 cubic meters per hour.

The main crude oil supply channel is the Druzhba pipeline, which originates in Russia and transits Belarus and the Ukraine before continuing on to the Czech Republic. The section of the pipeline that runs through Slovakia (part of Druzhba's southern branch), has five pumping stations and consists of two parallel lines for nearly all its length. While the Slovak section of the pipeline has a total capacity of approximately 400 kb/d, slightly more than half of this capacity is currently utilised to supply both Slovak and Czech refiners.

The Adria pipeline, which connects the Croatian port of Omišalj to the Hungarian refinery at Duna, provides a potential alternative supply for Slovakia. The Slovak section of the Druzhba pipeline is connected with the Adria by a 100-kilometre pipeline from Százhalombatta, Hungary to Šahy, Slovakia. While not used for normal operations (crude oil is occasionally transferred between the Slovak and Hungarian refineries), the section has an average capacity of around 90 kb/d. However, in order for this route to be a viable alternative to the full volumes imported via the Druzhba, the existing capacity of the Adria (200 kb/d) would need to be expanded to be able to supply both the Hungarian (Duna) and Bratislava refineries. Moreover, the connection between Százhalombatta and Šahy, only a small portion of which is in Slovakia, would need to be reconstructed.

The Ingolstadt-Kralupy-Litvínov (IKL) pipeline connecting the Czech refinery at Kralupy to the Trans-Alpine oil pipeline network (TAL) in Ingolstadt, Germany could also potentially contribute to the provision of crude oil supplies to Slovakia in a crisis. The IKL line currently has a capacity to deliver around 200 kb/d to the Kralupy terminal in the Czech Republic.

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Storage capacity

Slovakia's total combined oil storage capacity at the end of 2009 was just over 1.4 million m³. Most of the country's oil storage capacity is operated by two companies: Transpetrol (primarily crude oil) and Slovnaft (primarily product).

In 2013 Transpetrol and ASMR established a joint enterprise called "Company for Stockholding" which owns part of the crude oil storage capacity previously owned by Transpetrol, and the oil product storage capacity previously owned by ASMR. Storage capacity owned by the Company for Stockholding is primarily used by the EOSA.

Decision-making structure

The ASMR is responsible for oil emergency response preparedness. The ASMR functions as an independent body, and it reports directly to the government through the Council of Ministers. It is responsible for stockpiling and supply security of the main resources considered essential for the protection of public interests during crises.

ASMR stockpiles a wide variety of items including raw materials, foodstuffs and industrial equipment. However, the emergency oil stocks were separated from the state material reserves in 2013 and are now held and managed by the EOSA. The ASMR oversees the emergency oil stocks held by the EOSA. The chair of the ASMR serves as the head of the national emergency strategy organisation (NESO) and is responsible for initiating and co-ordinating a response to an oil supply disruption. The Oil Security Commission, which includes representatives from various ministries as well as from industry and the petroleum association, acts as a permanent advisory body of the ASMR chair in his capacity as NESO head. Within the ASMR, the Oil Emergency Department has the lead role in co-ordinating NESO activities and liaising with industry representatives.

In a supply disruption, the ASMR would prepare measures for managing the emergency and convene an emergency NESO meeting to discuss these measures. The ASMR chair, as the NESO chair, would then submit a draft order to the government which, based on the recommendations, would issue an official decision.

The use of EOSA-held crude and product stocks is central to Slovakia's emergency response policy. Slovakia considers the use of loans from agency reserves as the most effective way of participating in an IEA collective action. In a domestic situation that warrants the declaration of a state of emergency, the country's policy relies on industry participants to make an initial response to a supply disruption. Implementation of demand restraint measures and agency stocks would be a subsequent course of action if the initial efforts proved insufficient.

Stocks

Stockholding structure

Slovakia uses the agency stocks of the EOSA to fully meet its minimum stockholding obligation as a member of the IEA and the European Union. The law imposes the stockholding obligation on industry, but at the same time this obligation has to be delegated to the EOSA.

The Act No. 218/2013 Coll. is the legal basis for the EOSA's oil stockholding practices. This act defines conditions and types of oil which the EOSA is to hold for emergency purposes, and the methodology for calculating the minimum levels required to meet both the IEA and EU stockholding commitments. Agency stocks are financed by collecting fees from industry as a price for holding the stocks by EOSA on behalf of the industry.

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Crude or products

Total agency stocks of the ASMR at the end of 2013 were 4.9 mb. Nearly a quarter of this was in the form of gas/diesel oil, while some 60% was held as crude oil. In addition to the agency stocks of EOSA, industry stocks at the end of 2012 stood at 3.6 mb, with approximately 2.0 mb of this amount being held in the form of refined products.

Under IEA methodology, both EOSA and industry-held stocks count towards meeting the 90-day stockholding obligation. Thus roughly 55% of Slovakia's total stockholding obligation is covered by stocks held in the form of refined product.

Location and availability

Volumes of public stocks are stored on behalf of the EOSA by designated storage operators and refiners. Agency stocks held by private companies under contract with EOSA cannot be commingled with commercial stocks, and must be kept in separate tanks that are clearly marked as state emergency reserves. The product stocks are refreshed every three to five years by the company holding the stock, based on the contract agreement. The stockholder must keep detailed records, and regular inspections of both the records and storage terminals are carried out by the ASMR and EOSA.

EOSA stocks of crude oil are for the most part held at the Transpetrol terminals located on the Druzhba pipeline; roughly 10% are held at the refinery in Bratislava. The public reserves of motor fuels (gasoline, gas/diesel and jet kerosene) are located at the three terminals of Klačany, Hronský Beňadik, and Stožok connected to the Slovnaft product pipeline, as well as at the storage sites of Horný Hričov and Kapušany. Slovakia has a bilateral stockholding agreement with the Czech Republic, making it possible for Slovakia to hold emergency stocks in the Czech Republic.

Monitoring and non–compliance

EOSA performs volume and quality control on emergency stocks stored in facilities with which it has contractual agreements. The stockholders have to ensure samples are taken of emergency stocks on a regular basis for the purpose of quality checks in accredited laboratories, and to provide the results to EOSA. At least once a year, EOSA takes an inventory of all its emergency stocks.

Sanctions and penalties for breaching stockholding obligations are stipulated by provisions in particular stockholding contracts. The contracts refer to Act No. 218/2013 Coll. According to this act, the ASMR is authorised to impose a fine on the stockholder for: unauthorised use of emergency stocks (a minimum of EUR 665 000, rising to EUR 1 700 000 in the case of repeatedly unauthorised use of emergency stock); and breaching other obligations resulting from a stockholding contract (from EUR 35 000 to EUR 665 000).

When imposing a fine, the ASMR considers the severity, means, duration, impact of the lawless act and rate of culpability and the extent of harm.

Stock drawdown and timeframe

Slovakia could initiate a drawdown of public stocks under two main scenarios: within the framework of a domestic emergency and in conjunction with demand restraint measures, or in order to participate in an IEA collective action. In either case, the ASMR would propose to the NESO the conditions for a stock release, including the volume and types of stocks to be released, and the terms of release (likely in the form of loans). The ASMR chair would submit the NESO draft proposal to the government in an extraordinary meeting convened to discuss the emergency response. A final decision would be adopted with immediate effect.

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The release of agency stocks could be implemented either in the form of loans or sales. In the case of loans, the period of the loan would be limited by the duration of the emergency but not exceeding one year. A company taking a loan from the EOSA must pay an interest fee which is set at double the European Central Bank's interest rate as of the time of the loan contract. The company must also provide the EOSA with a financial guarantee covering the market price of the oil stocks. The first phase (from the decision of the Cabinet of Slovakia to release the stocks to the conclusion of the loan contract) would take seven days. The second phase (from the conclusion of the loan contract to the first release of stocks) would take three days.

In the case of selling agency stocks, the stocks would be offered at market price to all industry participants who are able to ensure that the stocks will be placed on the market. The process, including the preparation of the sale process to first stock deliveries, would take 14 days.

The maximum drawdown rate of agency stocks of crude oil is just over 180 kb/d, well above the country's total domestic refining capacity (127 kb/d). The maximum drawdown rate for finished products would depend on the specific storage site, and ranges from under 5 kb/d at Horný Hričov to some 30 kb/d at Kl'ačany and Hronský Beňadik.

Financing and fees

Agency stocks are financed by collecting fees from industry.The average stockholding costs for maintaining one tonne of agency stocks are EUR 35.55 a year. The costs associated with product stockholding are 2.5 times that of crude oil.

Other measures

Demand restraint

Demand restraint measures would be specified in the ASMR chair's proposal to the government, likely in parallel with the release of agency stocks. The level of the demand restraint measures would depend upon the severity of the crisis. In the initial stages, they would consist primarily of a mass media campaign calling for voluntary reductions in oil consumption.

Additional measures available to the Slovak government include the ability to limit motor vehicle speed, limit motor vehicle use on certain days or for specific kinds of transportation, or impose usage restrictions based on odd/even licence plates. They could also limit the opening hours of petrol stations, and regulate or otherwise direct the actions of oil importers and exports.

Legislation (Act No. 218/2013 Coll.) assigns responsibility for ensuring compliance with these different measures to various components of the Slovak government and sets fines for non-compliance. Industry and other bodies of the state administration would be obliged to provide all data deemed necessary by the ASMR for the monitoring and evaluation of the measures. The NESO would meet regularly to evaluate the effectiveness of the measures in comparison to current and past data, which might be collected on a weekly, bi-weekly or monthly basis. Depending on the results, the measures would be modified as deemed appropriate.

Fuel switching

The potential to switch away from the use of oil to another fuel source in the short term is inconsequential in Slovakia. The bulk of oil consumption (50%) is in the transport sector, where there is no capacity for short-term switching. Oil used in power plants is

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for the stabilisation of production, rather than for generation of electricity or heat, and therefore offers no opportunity for potential fuel switching.

Other

Short-term surge production capacity in Slovakia is considered inconsequential and not a potential emergency response measure.

Gas

Market features and key issues

Gas production and reserves

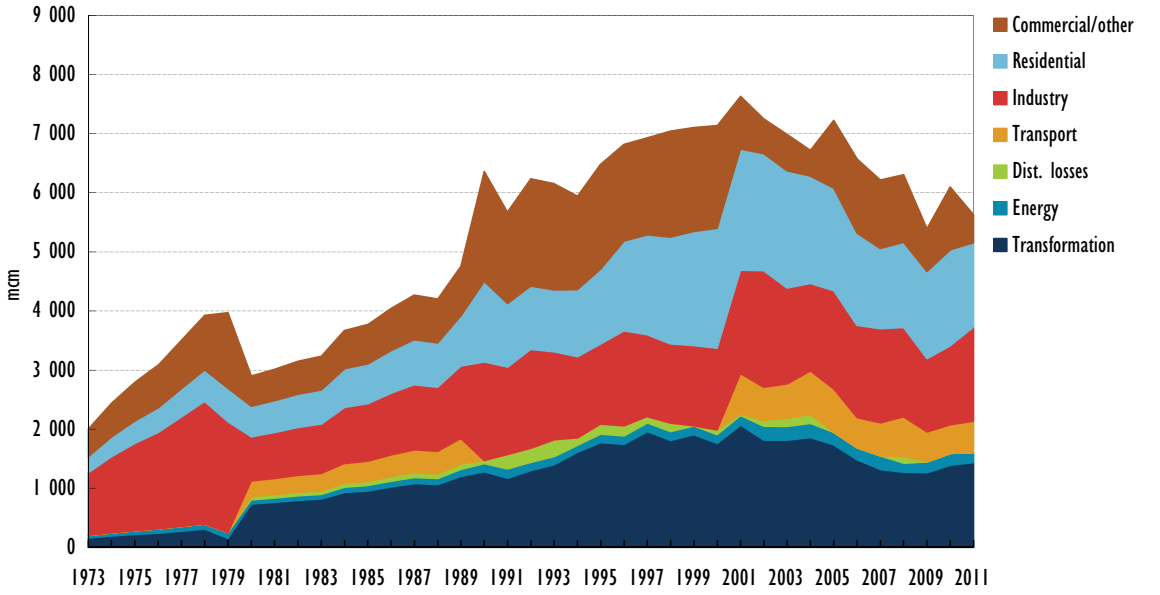
Only a small fraction of Slovakia's natural gas demand is met by domestic production. In 2012, some 150 mcm of gas was produced domestically, meeting less than 3% of its total demand. Production is expected to decline, dropping to roughly 90 mcm/y by 2018.

Gas demand

In 2012, demand for natural gas was some 5.3 bcm. Industry, the transformation sector and residential users each account for nearly a quarter of the total gas used in the country. Gas represented only 8% of the total share of electricity generated in the country.

Daily gas consumption ranges from some 5 mcm/d in the summer to around 25 mcm/d in the winter (inferring a 1:5 seasonality of gas demand). The highest average daily demand over the coldest 30-day period was in early 2006, at 35.9 mcm/d (when temperatures averaged -7.4°C). Historically, the highest daily peak was in December 2001 when gas use reached 46.9 mcm/d (-12.2°C).

Figure 4.23.6 Natural gas consumption by sector, 1973-2011



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Gas import dependency

The totality of Slovakian consumption is supplied by imports from Russia.

Gas company operations

Transmission and distribution activities in Slovakia were unbundled on 1 July 2006. Slovenský plynárenský priemysel (SPP), the dominant importer of natural gas into Slovakia, remains the parent company of the transmission system operator (TSO), Eustream, and the main distribution system operator (DSO), SPP distribúcia.

Eustream (a fully owned subsidiary of SPP), is one of the biggest transmission operators in Europe, focusing mainly on the transit of Russian gas towards Western and Southern Europe. SPP – distribúcia (also a fully owned subsidiary of SPP) is the biggest distribution network operator in Slovakia, while a number of small independent local distribution companies are also active in the country's gas distribution.

There are two storage system operators (SSOs) in Slovakia: Nafta and Pozagas. Nafta also operates the country's domestic gas production and is partially owned by SPP (56%) and E.ON Ruhrgas (40%). Pozagas is partially owned by SPP (35%), Nafta (35%) and GDF (30%).

SPP is the leading supplier of natural gas on the Slovak gas market with a share of more than 80% (in 2010). The company is 51% state-owned and 49% owned by Energetický a průmyslový holding, a.s. (EPH). Other companies active on the Slovak gas supply market are local branches of international companies, including RWE Gas, VNG and Shell. Other companies, such as Lumius Slovakia, ČEZ Slovakia and Vemex also supply gas to customers in Slovakia.

The number of shippers trading gas in Slovakia has been constantly increasing since 2005. At the beginning of 2010, Eustream had 20 shippers, three times the number in 2005, with portfolios of different entry-exit contracts. Physical nodes in the transit gas network (Vel´ké Kapušany, Lanžhot, Baumgarten) or domestic off-take points can be used to trade natural gas. In most cases it is over-the-counter trading because, with the exception of the Baumgarten node, there are no gas exchanges established on these points.

Gas supply infrastructure

Pipelines

Eustream, Slovakia's TSO, manages a domestic and transit pipeline network with three interconnection points. This is used both to transport natural gas for consumption in Slovakia and for transit of Russian gas to other end-user markets further west. The annual capacity of the system exceeds 90 bcm. In 2012, a total of 56.5 bcm of natural gas was transmitted through the transmission system. Transit gas arrives at the incoming transfer station of Veľké Kapušany on the Ukraine border (245 mcm/d capacity) and departs from outgoing transfer stations in Lanzhot at the Czech border (75 mcm/d), and Baumgarten at the Austrian border (150 mcm/d).

The physical reversal of flows is possible at the interconnection points of both the Czech and Austrian borders. The reversal at Lanzhot could be implemented within two hours, with a capacity to bring 36 mcm/d of gas from the Czech network. The possibility for reversal at the Baumgarten interconnection was achieved in October 2010, making it possible to bring 17 mcm/d of gas into Slovakia from Austria.

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A project to construct an interconnection with Hungary is underway, with "open season" procedures conducted in 2010 to assess market demand. The project will consist of a pipeline connection between Veľký Krtíš in Slovakia and Vecses in Hungary and would be part of the Visegrad 4 countries (the Czech Republic, Hungary, Republic of Poland and Republic of Slovakia), which aims to connect LNG terminals in Poland and Croatia. It is currently expected that the line will have an annual capacity of some 5 bcm and be operational in 2015.

Storage

Total natural gas storage capacity in Slovakia is 3.02 bcm (2012), with a maximum withdrawal rate of 39.25 mcm/day. All capacity is in underground storage facilities at the Láb complex in the west of the country. A new storage facility, within the Láb complex at Gajary-Baden, is under construction and is expected to raise the total capacity to 3.12 bcm, and the maximum withdrawal rate to over 40 mcm/day by 2014.

Additionally, a storage facility in the Czech Republic, at Dolní Bojanovice, and directly connected to the Slovak system is used physically balance the Slovak distribution network and ensure security of supply for households. Storage capacity at this site is 0.57 bcm and the maximum withdrawal rate is 8.8 mcm/day. At the same time, part of the Slovak storage facilities (0.5 bcm) is used to supply the Czech market.

Emergency policy

The Ministry of Economy (MoE) is responsible for natural gas emergency response. Following the January 2009 gas crisis in Europe, the Slovak government launched several initiatives in order to improve security of supply and increase capacity to deal with any similar future crises. The initiatives included infrastructure investments to increase capacity, improvements to interoperability between storage and transmission networks, and enabling the reversibility of physical gas flows. The Energy Act requires all suppliers operating on the domestic market to meet specific security of supply standards for their portfolio of protected customers. These supply standards are in compliance with EU Regulation No 994/2010 concerning measures to safeguard security of gas supply.

The Energy Act sets the standard of security of gas supply for suppliers. Suppliers are obliged to guarantee supply of gas under circumstances related to weather conditions or the disruption of normal supplies. Suppliers must be able to guarantee to meet the supply standard for 30 days, using measures including gas in storage, domestic production contracts and backup deliveries from other countries.

The main long-term gas supply contract for the Slovak market, signed in 2008 for 20 years, is between SPP and Gazprom Export. In order to reduce dependency on one source, as well as in an effort to diversify its portfolio, SPP concluded gas supply contracts with E.ON Ruhrgas and GDF SUEZ. In case of disruption of supplies from the east, these supplies can be obtained following the flow reversal of the gas pipeline system.

Other suppliers active on the Slovak gas market are local branches of major companies and have their supplies covered by the diversified portfolio of the parent companies or via contracts with Nafta, the domestic natural gas producer and storage operator.

The dispatching centre of the biggest DSO is responsible for announcing a crisis situation and its level, the measures to be taken and how the emergency situation will be managed. Other gas infrastructure operators (the TSO, the two storage operators and other DSOs) are obliged to co-operate with the dispatching centre to resolve the state of emergency as soon as possible.

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Emergency response measures

There are no emergency reserves of natural gas in Slovakia, as all storage is used for commercial purposes.

In order to meet the standard of security requirements under the Energy Act, suppliers are able to use storage volumes (as well as domestic production contracts and backup deliveries from other countries). However, there is no obligation placed on suppliers to guarantee the supply exclusively in the form of minimum reserves.

Demand restraint

In the event of a disruption to gas supplies, the dispatching centre of the concerned DSO is responsible for announcing and managing a crisis situation by applying restrictive measures (off-take levels and heating curves). Other gas infrastructure operators (TSO, SSOs and other DSOs) would be obliged to co-operate with the dispatching centre to eliminate the state of emergency as soon as possible.

Crisis severity levels would be used to determine the level of restrictions or cut-offs to end-users. Customers are divided into groups according to the volume and type of consumption (e.g. gas used for heating). Disruptions would be rated according to severity levels, determining the degree to which specific consumer groups would have supplies restricted or stopped.

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Spain

Key data

Table 4.24.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	27.3	4.7	3.3	3.2	3.0	4.1	8.7
Demand (kb/d)	1 009.9	1 433.2	1 607.3	1 441.0	1 385.3	1 289.0	1 156.1
Motor gasoline	188.6	196.8	172.2	131.3	122.5	113.5	-
Gas/diesel oil	316.1	529.2	705.0	677.6	635.8	591.3	-
Residual fuel oil	190.6	246.6	247.4	189.3	189.4	175.4	-
Others	314.7	460.7	482.7	442.8	437.5	408.7	-
Net imports (kb/d)	982.6	1 428.5	1 604.0	1 437.8	1 382.3	1 284.9	1 147.4
Import dependency (%)	97.3	99.7	99.8	99.8	99.8	99.7	99
Refining capacity (kb/d)	1 293.0	1 315.5	1 271.5	1 497.6	1 497.6	1 497.6	-
Oil in TPES (%)**	50	51	48	45	44	41	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.24.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	1 471	171	167	51	52	61	30
Demand (mcm/y)	5 742	17 578	33 634	35 824	33 276	32 496	35 549
Transformation	605	3 101	12 472	16 869	14 597	0	-
Industry	4 357	11 116	15 900	9 464	9 334	0	-
Residential	448	2 278	3 651	4 889	4 808	0	-
Others	332	1 083	1 611	4 602	4 537	0	-
Net imports (mcm/y)	4 271	17 407	33 467	35 773	33 224	32 435	35 519
Import dependency (%)	74.4	99.0	99.5	99.9	99.8	99.8	100
Natural gas in TPES (%)	6	13	21	24	23	23	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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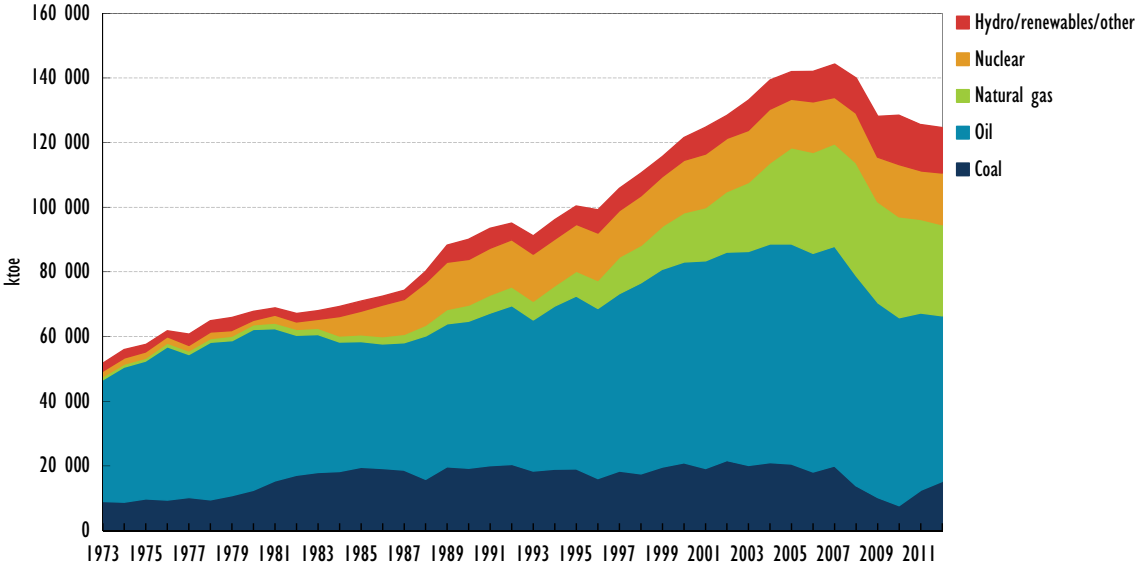
Figure 4.24.1 Total primary energy source (TPES) trend, 1973-2012



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Map 4.24.1 Oil infrastructure of Spain

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Map 4.24.2 Gas infrastructure of Spain

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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Country overview

Spain has very little domestic oil and gas production and relies heavily on imports, the sources of which are well distributed among Africa, the Middle East, countries of the former Soviet Union (FSU) and OECD member countries.

Oil consumption as a whole has dropped from its peak in 2007 of 1.61 million barrels per day (mbd) to 1.29 mb/d in 2012, although demand for middle distillates has remained relatively strong. The share of oil in total energy consumption as a whole is gradually declining. Spain imports virtually all its crude oil. In 2012 it imported 1.2 mb/d, with its largest volumes coming from Mexico (15%), Nigeria (14%), the Russian Federation (14%) and Saudi Arabia 13 (%).

Although Spain still imports some products, in 2012 Spanish exports of refined products increased by 31.2% compared to 2011. In fact, Spain has become a net exporter of petroleum products since July 2012.

Spain has a large and relatively complex refining industry, with nine refineries and a total nameplate capacity of 76.530 kilotonnes (approximately 1.5 mb/d).

Natural gas demand stood at 32.5 billion cubic metres (bcm) in 2012, below 2005 figures and far from 2008 data, when demand reached 40.3 bcm.

Spain imposes a stockholding obligation on both its oil and gas operators, and as such has emergency reserves of both oil and natural gas. Until 1995, Spain's emergency oil reserves were held only by industry, after which an agency was created for holding public stocks – the Corporación de Reservas Estratégicas de Productos Petrolíferos (CORES). The stockholding obligation in Spain is distributed between industry and CORES, with each holding approximately 50%. This provides the Spanish system with flexibility at the time of releasing stocks.

In the event of a gas emergency, Spain obliges natural gas shippers to maintain strategic stocks equivalent to 20 days of consumption in accordance with what the regulations define as "firm sales" during the preceding calendar year. The stocks must be maintained by traders and self-supplied consumers at any moment, and must be kept in underground storage only. The government assumes control of the strategic stocks in emergency situations.

Oil

Market features and key issues

Domestic oil production

Spain has very limited oil production, which stood at 4.1 thousand barrels per day (kb/d) in 2012 and is expected to reach 8.7 kb/d in 2018. Spain is thus highly reliant on imports of both crude and products, which it imports from a variety of different sources. All oil imports arrive by sea.

An estimated 50% of Spain's supplies are sourced on the spot market, thereby providing Spain with a high degree of flexibility.

Of note, Spain has a biofuel blending target of 4.1%, split in two sub-targets of 4.1% for diesel and 3.9% for gasoline.

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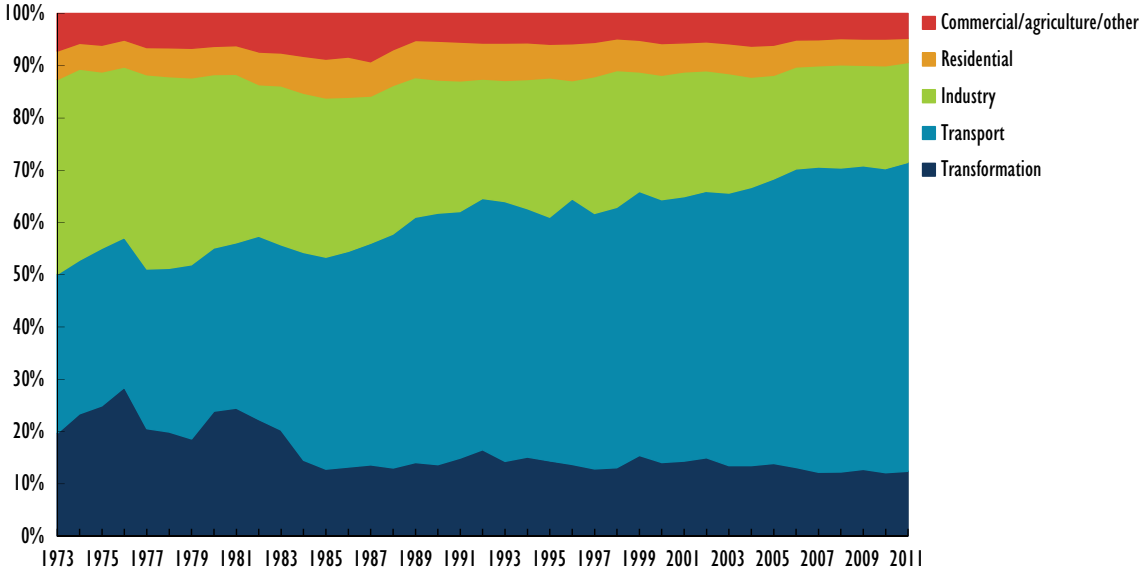
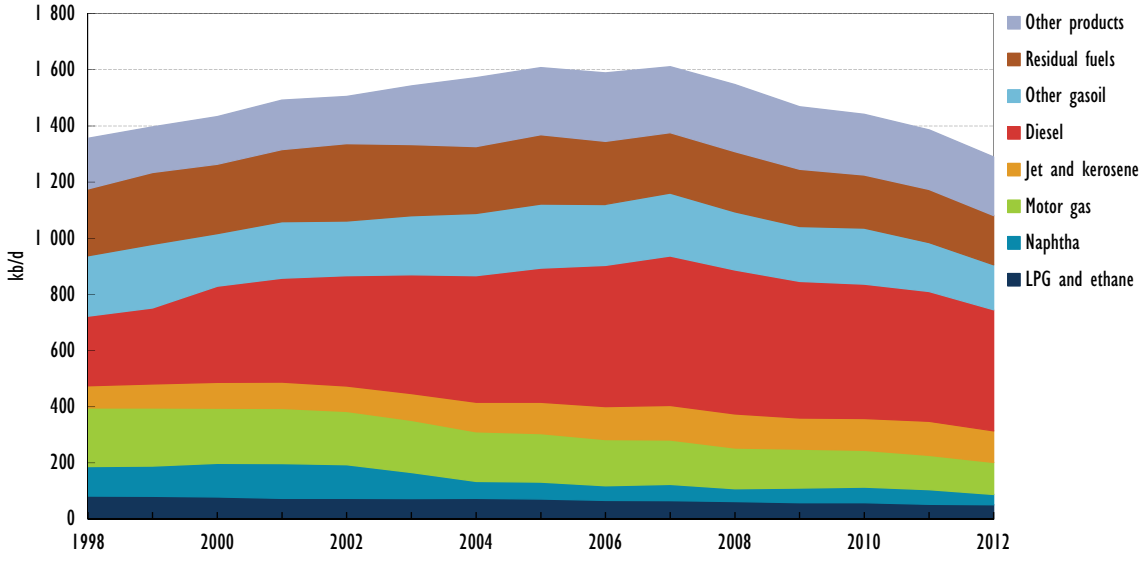
Figure 4.24.2 Oil consumption by sector, 1973-2011



Oil demand

In 2012, oil demand stood at 1.29 mb/d, down from 1.60 mb/d in 2005, and still down from 1.43 mb/d in 2000. Although overall product demand has decreased slightly over the last decade, middle distillate demand has still grown by 12% year on year.

Figure 4.24.3 Oil demand by product, 1998-2012



Oil is primarily used in the transport sector, which accounted for 59% of total consumption in 2011 and according to Spanish statistics for 63.4% of oil consumption in 2012. By contrast, the industrial sector's share was 19% in 2011 and, according to Spanish figures, 17.9% in 2012.

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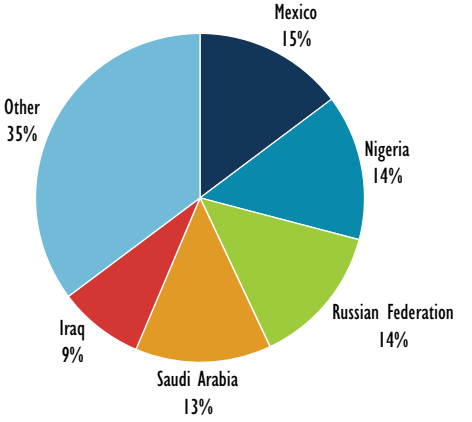
Imports/exports and import dependency

Spain imports virtually all its crude oil. In 2012 it imported 1.2 mb/d, with its largest volumes coming from Mexico (15%), Nigeria (14%), Russian (14%) and Saudi Arabia 13 (%). As for oil products, as is the case in many European countries, Spain carried out a "dieselisation" of vehicle fleet since 1999, when, for the first time, Spain registered more diesel cars than gasoline. As other European countries, traditionally Spain has been a net importer of middle distillates. Nevertheless, the situation has changed dramatically owing to the increase in refining capacity (an increase of 9% in 2012 from 2011) and weak domestic demand caused by the economic downturn. In 2012, exports of petroleum products increased 31.2% compared to 2011, reducing imports by 28%. In fact, Spain has become a net exporter of petroleum products since July 2012, and is also a net exporter of gasoil.

Oil company operations

The Spanish oil retail market is fully open to competition. Imports, exports, trade and prices are free. The government intervenes only to protect competition and to avoid abuse of dominant positions. At the end of 2012, there were around 10 400 filling stations. Spain's retail network is highly concentrated, in spite of the number of operators in the country. More than 60% of the market is covered by companies such as Repsol (35%), Cepsa (15%), BP (6%) and GALP (6%). Law 11/2013 of 26 July, implementing measures to support entrepreneurs and to foster growth and job creation, adopted urgent measures to reinforce market competition in the retail market by regulating clauses in exclusive contracts between retailers and major operators, by simplifying administrative procedures to set up new filling stations and by capping market share of operators accounting for 30% or more of total points-of-sale.

Figure 4.24.4 Crude oil imports by origin, 2012



Oil supply infrastructure

Refining

Spain has a large and relatively complex refining industry, with nine refineries and a total nameplate capacity of 76.530 kt (approximately 1.5 mb/d), distributed among three companies: Repsol (52% of total capacity), Cepsa (38%) and BP (10%). Average utilisation rates in 2012 stood at 84%. Eight of the nine refineries are located on the coast. Only Repsol's Puertollano refinery is located inland, and is supplied via a 358-km-long pipeline linked to the port and refinery of Cartagena.

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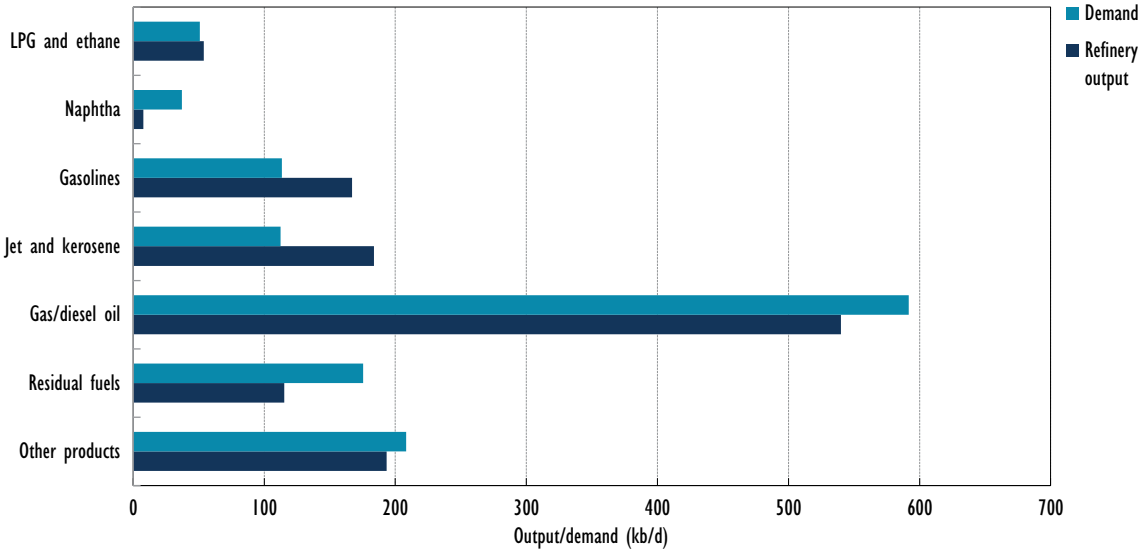
Recent refining investments aimed to redress the supply shortfall of middle distillate products, notably diesel and jet fuel, as well as to reinforce international competitiveness. BP completed a coker unit at its Castellón refinery in early 2009. Cepsa has upgraded the two refineries at Algeciras and particularly Huelva. Repsol YPF has invested over EUR 3 billion in Cartagena and has built a delayed coker unit at its Bilbao refinery.

Figure 4.24.5 Refining output vs. demand, 2012



Ports and pipelines

Spain enjoys a flexible and efficient system, thanks to its wide geographic and interconnecting coverage, including an extensive network of pipelines and storage capacity connected to refineries. It has an efficient and flexible system, where transport and storage services are integrated, making products available in any of its storage facilities.

The CLH (Compañía Logística de Hidrocarburos) oil pipeline network is over 4 000 km long. It links the main eight peninsular refineries and the main import ports with 39 storage plants of the company which serve the mainland, and with 28 storage plants which supply the main airports. The network has a central dispatching unit at Torrejón, close to Madrid, which supports, manages and supervises the automatic systems in all the installations, and from which it is possible to operate directly over any of their systems and resolve any possible incidents.

In addition to the CLH pipeline network, Repsol owns two parallel pipelines transporting crude oil and products between the Cartagena and Puertollano refineries.

The oil pipeline network is an integrated network, owned 100% by CLH (except for Repsol's pipelines, mentioned above) but third-party access (TPA) is guaranteed to both logistic and storage facilities by means of a negotiated procedure which has non-discriminatory, transparent and objective technical and economic conditions; in addition, the prices charged must be made public.

Storage capacity

The Spanish logistic system is a competitive market with growing storage capacity and many players.

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There are 41 companies offering storage service in Spain at 138 sites (including airports), some of which are subsidiary companies of oil operators. Most of the storage sites, including the largest ones, are connected to Spain's CLH pipeline network.

Total storage capacity in 2010 was some 28.3 million cubic metres (MCM), or 178.6 million barrels (mb). The coastal refineries are the main sites for crude imports and storage. These refineries also import a substantial share of refined products through the nearby ports. Total on-site storage capacity at the country's refineries amounts to 8.1 mcm (around 50 mb). The remaining volumes of refined products are imported directly to storage facilities, located mainly in Barcelona and Bilbao.

CLH is the main storage capacity holder, with a storage capacity of 7.9 mcm distributed in 39 storage facilities and 28 airport facilities. The breakdown by product is as follows:

- unleaded petrol: 1.1 million m^3
- diesel: 5.3 million m^3
- aviation kerosene: 1.2 million m^3
- fuel and IFOs: 0.3 million m^3.

Decision-making structure

The Spanish national emergency strategy organisation (NESO) is part of a rather complex structure of emergency organisations in Spain.

On the ministerial level, the Government Delegate Commission for Crisis Situations (CDGSC) holds ultimate responsibility for handling crises. This ministerial commission is supported on a tactical level by the National Civil Emergency Planning Committee (CNPCE). On the operational level, nine sector working committees are placed under the CNPCE, including the National Energy and Mining Resources Committee (CSREM), which forms the basis for NESO. A decision by the Council of Ministers of January 1988 constitutes the legal basis for the operation of both CSREM and CNPCE. The main functions of these committees are supply/demand analysis, demand restraint plans and preparation of rationing schemes.

The CNPCE is the body that must propose to the CDGSC the measures to be adopted in response to a supply disruption, following consultation with committees in the affected sector. Members of the CSREM include: the General Directorate of Energy and Mines from the Ministry of Industry, Energy and Tourism; CORES and, eventually, the National Competition Commission (CNMC). The CSREM also includes various operators and logistics and storage companies. To ensure the effectiveness of the CSREM, representatives from the Ministry of Industry, Energy and Tourism, the CNMC and CORES, and from reporting companies that are members of the CSREM, participate in various training seminars and workshops.

The National Security Department (NSD) is a body directly linked to the President's Cabinet, and would also play a role in a supply shortage. It is in charge of the proper functioning of the National Crisis Situation Management System, including the study and proposal of the legal framework.

Preventive actions are developed through scenario planning at the sectorial level. In the case of the energy sector, the CSREM draws up a range of reports and crisis scenarios associated with electricity, fuel and gas supplies, as well as necessary response measures at the national level.

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Stockholding structure

Law 34/1998 on the Hydrocarbons Sector establishes the government's power to oblige all operators to hold emergency stocks up to a maximum of 120 days of sales or consumption and several measures that the government can implement during a supply disruption to reduce oil demand.

Recently, Royal Decree of Law 15/2013, dated 13 December, on the restructuring of the business public entity named Operator of the Railway Network (ADIF) and implementing other urgent measures on economic affairs, aligned Law 34/1998 to the terminology and general framework of European Commission Council Directive 2009/119/EC of 14 September 2009, imposing an obligation on member states to maintain minimum stocks of crudel oil or petroleum products, namely appointing CORES as the national central stockholding agency. Royal Decree 1716/2004 which regulates the stockholding obligation of minimum security stocks, the natural gas diversification of supplies and the stockholding agency, establishes the stockholding agency (CORES) to be in charge of creating and maintaining the strategic stocks and monitoring compliance with the minimum emergency stock obligation. The royal decree specifies the obligation for operators to hold a minimum of 92 days of stocks as emergency stocks, and stipulates that the government can regulate the use of emergency stocks during a supply disruption.

Crude or products

At the end of 2012, Spanish public stocks were made up of 54% middle distillates, 35% crude oil, 8% motor gasoline and 3% residual fuel oil.

Location and availability

CORES gives some consideration to geographical criteria in deciding where to maintain stocks, in order to maximise flexibility in the event of a domestic oil supply disruption.

Monitoring and non-compliance

Stockholding compliance is controlled annually by CORES, and any breach by a company can be punished by the Ministry of Industry, Energy and Tourism. Spanish law distinguishes between three different levels of infringement and stipulates that penalties can range from EUR 600 000 for minor violations up to EUR 30 million (and a one-year activity ban) for very serious violations.

Stock drawdown and timeframe

In the event of an IEA collective action, the decision to release either industry or CORES stocks is made by the government in accordance with various criteria. In the past, industry stocks releases have been chosen over those of CORES because of cost efficiency and agility. The procedure of putting industry stocks on the market usually consists of a reduction of the obligation. This method has been applied in the last co-ordinated actions.

The Spanish government also has the option of releasing public stocks. In the event of a CORES stock release, it would make additional barrels of oil available to operators, based on their market share on the Spanish market. The purchase of stocks by companies is carried out through a tender offered to all Spanish operators. CORES has vast experience

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in carrying out this type of operation, as the same procedure has been followed each time that CORES has acquired or sold product.

CORES maintains its strategic reserves mainly within the oil and logistic operators' facilities (either segregated or commingled, according to storage agreements), and at its own facilities in Puertollano and Cartagena. All crude stocks (both industry and public) are located in refineries.

Financing and fees

CORES finances its activities by collecting a monthly fee from the operators, distributors and consumers obliged to keep security stocks. CORES calculates the fee on an annual basis based on a budget, which is then approved (or modified) and published by order of the Ministry of Industry, Energy and Tourism. CORES is not state-funded and stock purchases are financed through bilateral loan agreements or public issues in the financial markets.

Other measures

Demand restraint

The transport sector makes up the majority of oil consumption in Spain, representing 59% in 2011. Thus the likely, most effective demand restraint measures would be targeted at the use of transport fuels.

Article 49 of Law 34/1998 of 7 October and Article 39 of Royal Decree 1716/2004 of 23 July establish that in situations of supply shortage, the Council of Ministers has the legal ability to take numerous measures to restrain demand, such as carpooling, driving bans according to odd/even licence plates, speed limits, public transport fare reduction and an increase in public transport services. The legal prescription of these measures gives the Spanish government both power and flexibility in the case of a supply disruption.

Certain demand restraint measures were put in place in March 2011 as a result of the Libyan crisis, such as speed reductions, but there has been no calculation of volumetric savings.

Fuel switching

In the case of an emergency, some diesel-fuelled power stations can switch to heavy fuel oil. However, since less than 1% of electricity consumed in Spain is produced by oil-fuelled power plants, the impact of an eventual oil crisis on the power supply on consumers would be negligible.

Other

As a result of previous incidents at the national level, such as the Puertollano refinery accident in 2005, relocating emergency reserves has proved to be a useful and effective way to deal with regional supply disruptions. The CLH infrastructure has a major role in enhancing flexibility so that CORES and the Ministry of Industry, Energy and Tourism can put in place measures to relocate emergency reserves quickly. As a result, demand can be met with the existing resources without any need to implement additional measures or restrictions to consumption.

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Gas

Market features and key issues

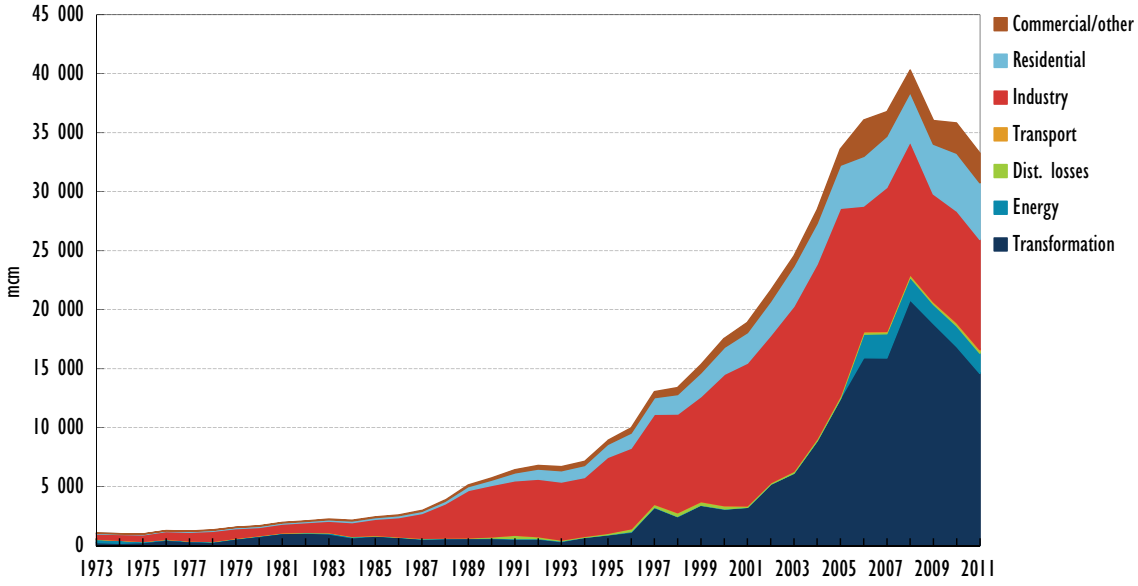
Gas production and reserves

Although domestic production is negligible (only 0.3% of consumption) owing to the resumption of production of the Poseidón gas field, the volume of natural gas extracted from the gas fields has picked up slightly from 2010 onwards, reaching 61 mcm in 2012 (as compared to just 14 mcm in 2009).

Gas demand

Natural gas demand stood at 32.5 bcm in 2012, or 365 351 gigawatt hours (GWh) according to Spanish statistics, below 2005 figures and far below 2008 data, when demand reached 40.3 bcm (or 450 726 GWh).

Figure 4.24.6 Natural gas consumption by sector, 1973-2011



The transformation sector (natural gas used in the process of transformation into another energy form, such as electricity, heat, etc.) is the largest consumer with a 39% share of the total demand, followed by the industry sector (31% share) and the residential sector (12%).

Peak demand stands at around 157 mcm/d. Although the figure is equivalent to 12 times the withdraw rate from underground storages (12.8 mcm/d), supply is widely secured by the withdrawal capacity of liquefied natural gas (LNG) terminals (170 mcm/d) and the entry capacity of international gas pipes (71 mcm/d in winter and 75 mcm/d in summer).

Gas import dependency

Spain has a regulation on the diversification of natural gas supplies, with a threshold of a maximum of 50% of supplies coming from the same country on a yearly basis. Royal Decree 1766/2007 requires that, in case the total of all natural gas supplies destined

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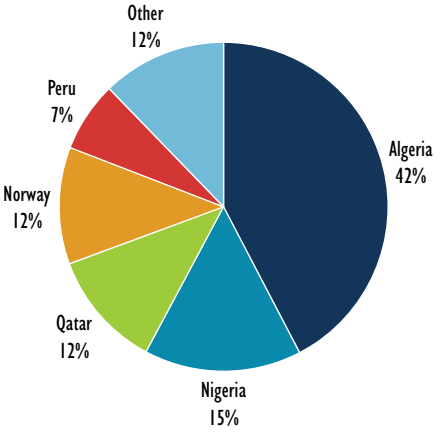
for national consumption sourced from the same country goes beyond the foreseen threshold, shippers supplying more than 7% of the national demand are obliged to diversify their portfolio. In this way they do not to procure more than 50% of their supply from the same country.

In 2012 Spain imported 35 bcm of natural gas – 1.2% less than 2011 figures – from nine different countries: 41.7% of total imports were from Algeria, followed by Nigeria (15.5%), Norway (11.7%) and Qatar (11.6%).

The Spanish gas supply is well diversified with a large number of suppliers and a large proportion of LNG supply. In 2012, 60.2% of Spain's gas imports were LNG deliveries, with the remaining 39.8% being pipeline supplies.

Figure 4.24.7 Natural gas imports by source, 2012



Gas company operations

The Spanish natural gas sector is privately owned and operated; this includes production, distribution, and transmission. Gas Natural Fenosa is the leading shipper in Spain.

Enagás owns and operates most of the Spain's high and medium pressure grid, as well as three of the country's six LNG regasification terminals, at Huelva, Barcelona and Cartagena. Since December 2006, the government has limited individual company ownership of Enagás to a maximum of 5%.

Gas supply infrastructure

Ports and pipelines

The international connections of the Spanish gas system include two gas import pipelines from Algeria and four reversible international connections, two with France – Larrau (Navarra) and Irún (Guipúzcoa) – and two with Portugal – Badajoz and Tuy (Pontevedra).

The development of gas interconnection capacity between France and Spain has been a priority for the European Regulators' Group for Electricity and Gas (ERGEG) South Gas Regional Initiative (SGRI). The investments required were decided on the basis of long-term commitments taken by shippers through the "open seasons" of 2013 and 2015. These market tenders resulted in several agreements:

- The total capacity at Larrau, available from the end of 2013, amounts to 165 GWh/day in both directions.

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- The total capacity at Irún, available by 2015, will amount to 60 GWh/d in both directions.

  Furthermore, the 8 bcm MedGaz deepwater pipeline between Beni Saf, Algeria and Almería became operational in March 2010. This connection reinforced and diversified the supply to Southern Europe, supplying gas directly from Algeria without requiring transit through third countries (namely Morocco).

  Spain has six operating regasification plants located at the main entry points of the natural gas system. These plants are an essential element in the security of supply as they have a regasification capacity of 60 bcm per year, compared to a natural gas demand of 32.5 bcm in 2012.

Storage

Spain's LNG terminals have a total LNG storage capacity of 3.2 mcm (equivalent to 1.88 bcm of gas storage), with a maximum emission rate of 6.86 mcm per hour. The most recent upgrades are a third LNG tank in the Sagunto plant and the Barcelona terminal, whose additional send-out capacity now reaches 1.95 mcm per hour.

The regasification plants service will be further reinforced in the future because of increased emission capacity on the transmission system and LNG storage tanks. By 2015, the third LNG tank in the Bilbao plant will be operational and two new regasification plants in the Canary Islands are envisaged for the following two years. Thus, LNG storage will reach 3.7 mcm and the maximum drawdown rate will reach 7.16 mcm/h.

There are currently four operating underground storage (UGS) sites:

- Gaviota (offshore, Basque Country), Serrablo (Huesca) and Marismas (Huelva) are depleted fields with a total working gas capacity of 1.72 bcm (total injection capacity 8.9 mcm/d and withdrawal capacity of 12.8 mcm/d).
- Yela (aquifer, Guadalajara) became operational in 2012. Today, cushion gas and working gas injection is still continuing and withdrawal capacity is currently undergoing testing.

  Moreover, the new UGS Castor was commissioned in April 2012 and cushion gas injection was started in May 2013. However, in view of the induced seismicity, further studies were commissioned. In the meantime, operations were suspended until results of these studies become available.

  Therefore, total UGS capacity is forecast to reach 4.7 bcm in the long term, with injection rates of 30.7 mcm/d and withdrawal capacity rates of 56.6 mcm/d.

  The total available capacity of Spanish UGS is managed as a whole by the technical system manager in order to optimise the working of the network and to minimise gas flows from storage to consumers.

Emergency policy

The Spanish Natural Gas System is based on the System Technical Management Rules, which has a procedure to cope with exceptional situations that may affect the normal operation of the system.

The system operator is responsible for putting this procedure into practice, declaring the level of emergency and co-ordinating the actions of the system users – namely traders, infrastructure owners and others. It also must keep the Ministry of Industry, Energy and Tourism, as well as the CNMC, properly informed at all times, and must be co-ordinated with the electricity system operator, as far as gas supply for electricity generation is concerned. An operation group, composed of representatives of the main gas users, gives support to the system operator in making decisions.

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Order ITC 3128/2011 obliges natural gas shippers to maintain strategic stocks equivalent to 20 days of consumption in accordance with what the regulations define as "firm sales" (supplies that cannot be interrupted, either for commercial or technical reasons) during the preceding calendar year. Since the entry into force of Law 12/2007, the obligation to maintain "operational stocks" no longer applies. CORES is responsible for controlling the minimum stockholding obligations that correspond to operators in the natural gas and LPG sectors, as well as for verifying the operators' obligation to diversify their natural gas supplies. However, CORES does not hold "strategic stocks" in the natural gas and LPG sectors.

The stocks must be maintained by shippers and self-supplied consumers at all times and must be kept in underground storage only. The government assumes control of the strategic stocks in emergency situations.

Emergency response measures

Several stakeholders are given specific responsibilities in the event of a gas crisis, notably with regard to making gas stocks available to the market.

ENAGAS, as the technical system manager, would declare one of three levels of exceptionality of the emergency situation, and would co-ordinate the actions of system users. The Ministry of Industry, Energy and Tourism would establish conditions and terms for the use of gas stocks by ENAGAS. CORES is responsible for monitoring the gas stocks, and would be responsible for ensuring that the obligated entities fulfil their responsibilities with regard to stock releases.

The Spanish system is designed to be highly flexible (LNG diversification, etc.), and thus fuel switching is not regarded as a priority tool to face disruptions. Nevertheless, combined-cycle power plants can work with an alternative fuel (mainly diesel) for short periods of time.

Additional measures

Every year, the Spanish government designs a winter action plan, which lays out additional requirements for shippers from 1 November to 31 March. The winter action plan is approved on a yearly basis by the Directorate-General for Energy Policy and Mining at the Ministry of Industry, Energy and Tourism. The plan includes minimum stocks levels, a method to predict the increase of demand in case of a cold spell and a cold spell definition.

Spain's gas network is based on the N-1 principle, whereby in the event of disruption of any large piece of infrastructure, the remaining infrastructure is capable of meeting total gas demand for the area.

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Sweden

Key data

Table 4.25.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Demand (kb/d)	335.7	362.0	359.6	335.9	324.1	310.8	286.7
Motor gasoline	96.4	91.8	94.0	79.0	73.3	66.1	-
Gas/diesel oil	107.3	111.0	102.3	106.8	114.9	113.5	-
Residual fuel oil	49.6	55.6	57.5	55.0	43.0	39.3	-
Others	82.3	103.6	105.7	95.0	93.0	92.0	-
Net imports (kb/d)	335.7	362.0	359.6	335.9	324.1	310.8	286.7
Import dependency (%)	100	100	100	100	100	100	100
Refining capacity (kb/d)	428.0	427.0	434.0	442.7	442.7	442.7	-
Oil in TPES (%)**	30	29	27	27	28	26	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.25.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	0	0	0	0	0	0	0
Demand (mcm/y)	616	805	820	1 564	1 303	1 130	1 302
Transformation	235	297	255	818	544	0	-
Industry	287	344	375	481	486	0	-
Residential	39	86	51	85	78	0	-
Others	55	78	139	180	195	0	-
Net imports (mcm/y)	616	805	820	1 564	1 303	1 130	1 302
Import dependency (%)	100	100	100	100	100	100	100
Natural gas in TPES (%)	1	2	2	3	2	2	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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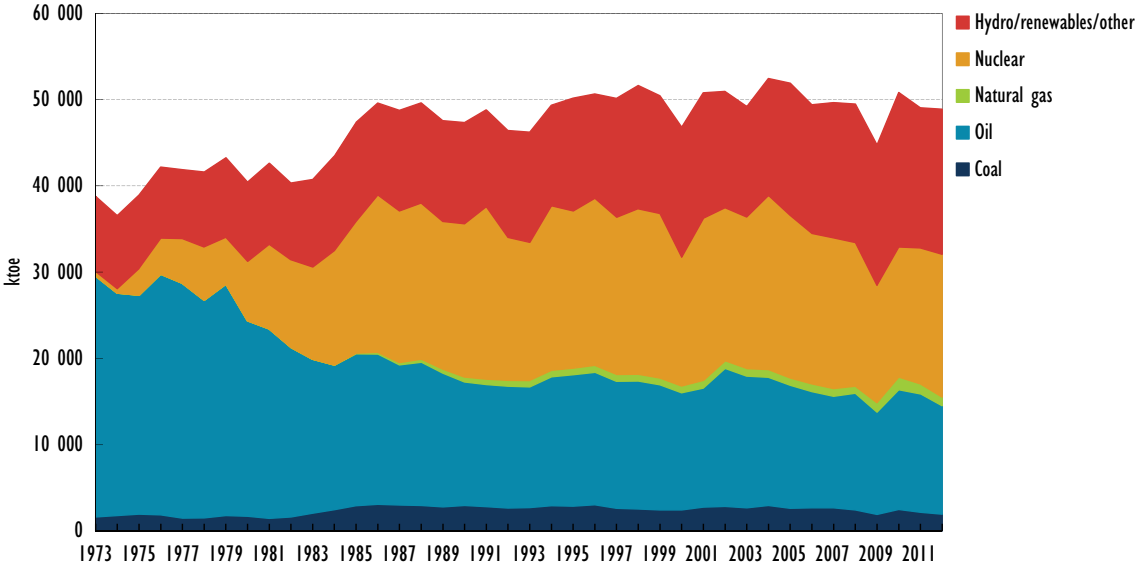
Figure 4.25.1 Total primary energy source (TPES) trend, 1973-2012



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Map 4.25.1 Oil infrastructure of Sweden

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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Map 4.25.2 Gas infrastructure of Sweden

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Country overview

In 2012, Sweden's total primary energy supply (TPES) was made up of oil (26%) and gas (2%). With coal representing 4% of TPES, Sweden has the lowest share of fossil fuels in the energy supply mix among International Energy Agency (IEA) member countries. This is a significant difference from the mid-1970s, when fossil fuels made up three-quarters of Sweden's energy supply, and is the result of a concerted effort to move away from the use of oil towards developing nuclear and renewable energy sources. Sweden's energy policy seeks to further increase its share of renewable energy sources and plans to provide half of all energy, and 10% of all transport needs by 2020. Sweden's use of fossil fuel is also to be further reduced by fully eliminating their use for heating purposes by 2020 and by having a vehicle fleet in Sweden that is "independent" of fossil fuels by 2030. Under this policy, demand for both oil and natural gas is anticipated to decline from its current levels.

Oil demand in Sweden was nearly 310 thousand barrels per day (kb/d) in 2012. Although Sweden is fully dependent on imports to meet its domestic oil demand, it is a net exporter of refined oil products. Overall oil demand will likely decline in the coming decade, but demand for oil within the transport sector is expected to grow.

The consumption of natural gas in Sweden totalled 1.3 billion cubic metres (bcm) in 2011, all supplied via a single interconnector with Denmark. While natural gas plays only a minor role in Sweden's TPES, its role in the energy supply of southern and western Sweden is much more substantial, accounting for around 20% of the area's total energy use. Around 30 large consumers, including combined heat and power (CHP) plants, account for roughly 80% of total gas demand in the country, while households and other small consumers, numbering over 33 000, account for 2% of the total.

The Swedish Energy Agency (SEA), under the Ministry of Enterprise, Energy and Communications, has the main responsibility for both oil and natural gas emergency response policy. Sweden fulfils its oil stockholding requirements to both the IEA and the European Union by placing minimum stockholding obligations on industry and major consumers. During a disruption of supply and as a contribution to an IEA collective action, Swedish authorities would reduce the minimum obligation, thereby granting operators permission to draw stocks below the minimum level.

In a natural gas crisis, supplies to protected customers (i.e. households) would be safeguarded while the physical balance of the gas system would be maintained by restricting or discontinuing supplies to non-protected customers in a crisis. System operators are obliged to have in place crisis plans for dealing with emergency situations, including a strategy for reducing supplies to customers.

Oil

Market features and key issues

Domestic oil production

Sweden has no indigenous oil production and is thus 100% dependent on imports. While Sweden depends fully on imports to meet domestic oil demand, the country is a net exporter of refined oil products. In 2012, Swedish refineries processed some 20.6 million tonnes (Mt) of crude oil, or roughly 413 kb/d. The total product output from refineries was 21.4 Mt, or 434 kb/d.

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Oil demand

Oil product demand in Sweden averaged nearly 330 kb/d in 2011. The vast majority of this was consumed in the transport (66%) and industry (21%) sectors. Total oil use has declined at an annual average rate of nearly 1% since 2000. The decline in oil demand has been driven by trends to switch away from oil, for example replacing fuel oil and gasoil used for heating with district heating and heat pumps. The largest decline in oil use has been in the industry sector, which has moved towards greater use of electricity and biofuels.

Figure 4.25.2 Oil demand by product, 1998-2012

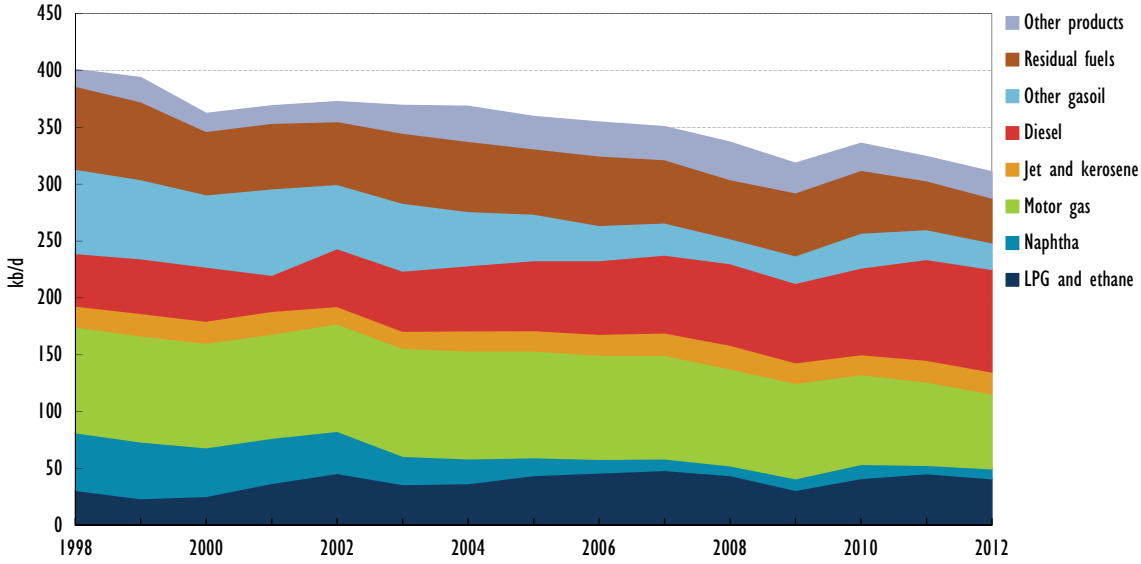
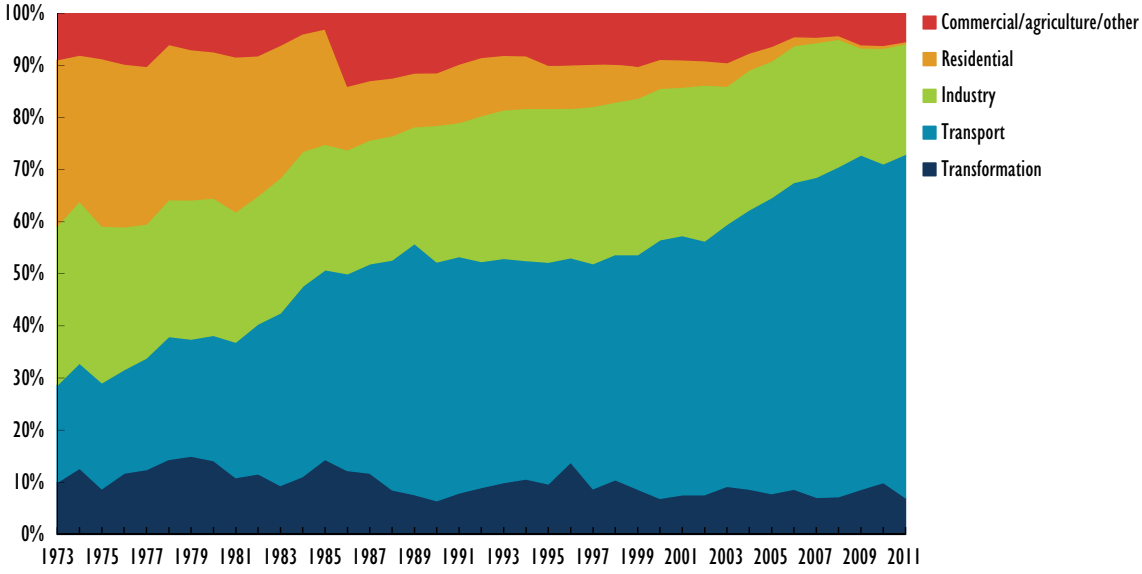


Figure 4.25.3 Oil consumption by sector, 1973-2011



While overall oil consumption has been on the decline, demand in the transport sector has continued to increase gradually, rising at an annual average rate of 0.6% over the period from 2000 to 2010 (the latest year for which consumption by sector is available).

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At the same time, the mix of transport fuels has shifted substantially towards a greater share of diesel. The relatively rapid transition from gasoline to diesel in road transportation can be largely attributed to EU regulations regarding CO_2 emissions for new cars (which favour diesel engines) and growth in the use of heavy goods vehicles. Demand for diesel grew at an annual average rate of 4.7% from 2000 to 2011, compared to a decline in demand for motor gasoline (-1.2% per year) over the same period.

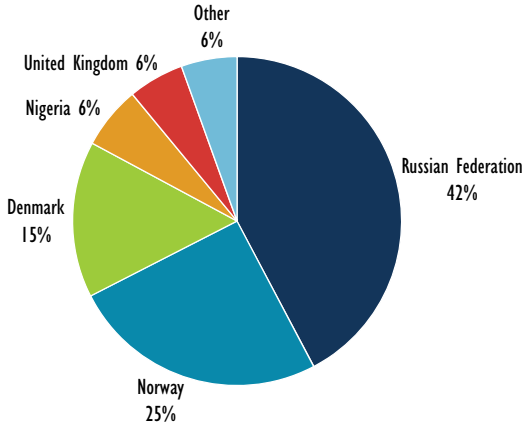
Total oil demand is expected to continue to decline in the coming years at an annual average rate of -0.4%. This rate would infer oil demand of around 315 kb/d by 2020. At the same time, demand for diesel is expected to continue to rise, reaching over 110 kb/d by 2020, compared to just under 80 kb/d in 2011.

Imports/exports and import dependency

In 2012, Sweden imported 20.6 Mt of crude oil, or an average of roughly 416 kb/d, primarily from the Russian Federation (42%), Norway (25%) and Denmark (15%). Additionally, Sweden imported some 0.4 Mt of feedstocks in 2012. Russia's share in Sweden's total crude imports has risen significantly over the past decade, having represented less than 10% of total crude imports in 2000.

As refining output exceeds domestic demand, Sweden is a net exporter of refined products. In 2012, product exports averaged 275 kb/d compared to product imports of 137 kb/d. This was mostly made up of reciprocal trade of the main products with Denmark, Norway and the United Kingdom.

Figure 4.25.4 Crude oil imports by origin, 2012



Oil company operations

Three companies operate refineries in Sweden, with Preem AB operating the country's two largest refineries; together they represent about 80% of the country's total distillation capacity. St1 operates the third largest refinery, located in Göteborg, which was formerly operated by Shell until its acquisition by St1 at the end of 2010. Nynas Refining also operates two smaller refineries specialising in bitumen and lubricants.

The Swedish oil retail market is dominated by four companies; Preem, Statoil, QK-Q8 and St1 (with retail stations branded Shell), which together accounted for roughly three-quarters of the market. Companies operating on the Swedish oil market are represented by the Swedish Petroleum and Biofuels Institute (SPBI).

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Refining

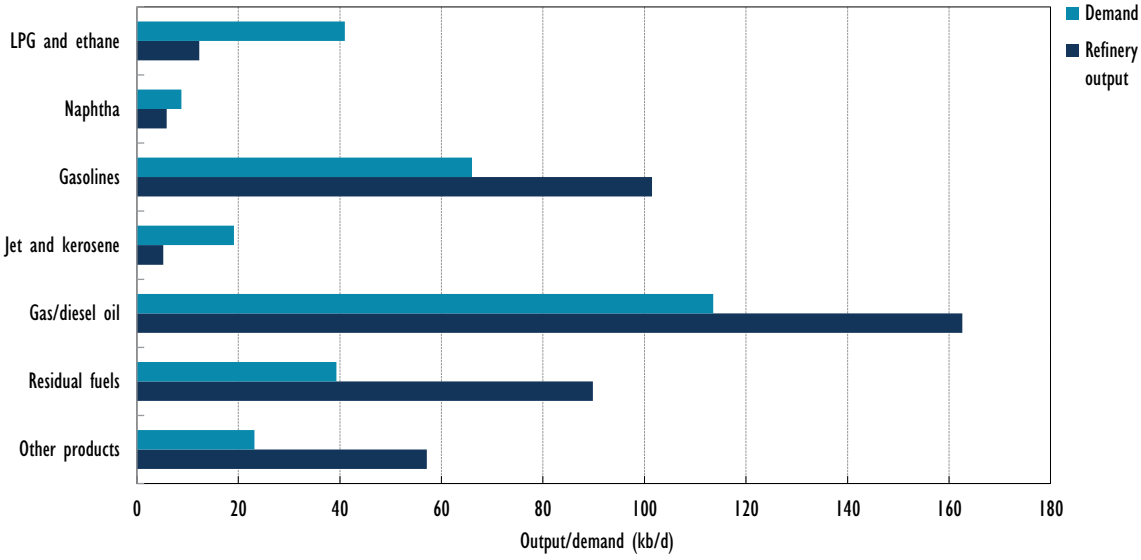
Sweden's five refineries have a total crude distillation capacity of roughly 435 kb/d. The largest of these, the refinery at Lysekil (Preem), has a crude capacity of 210 kb/d. Three of these refineries (Preem, St1 and Nynäs Refining) are located in Göteborg and together account for 45% of the country's total crude capacity. The fifth refinery (Nynäs Refining) is located south of Stockholm, at Nynäshamn.

Sweden introduced environmental classifications in 1991 which divided diesel into three classes, Mk3, Mk2 and Mk1. Mk3 followed the European diesel standard, EN 590, while Mk2 and Mk1 held more stringent requirements on specific parameters. Mk2 was a fuel specification that some of the refineries could produce with minor upgrades, while Mk1, with a sulphur content of less than 5 ppm (parts per million), required significant upgrades in all five refineries. Within a few years Mk1 became the major diesel fuel used in Sweden, and in 2012, about 98% of the diesel fuel sold was of Mk1 quality.

The Preem refinery at Lysekil underwent major upgrading over the past decade in order to produce greater volumes of sulphur-free gasoline and diesel oil. This has positioned Preem as the largest supplier of Mk1 diesel in the Swedish market.

Sweden applies an energy tax on diesel which is differentiated according to its classification; since 1 January 2011 the environmental tax on Mk1 is EUR 0.17 per litre, compared to EUR 0.20 per litre for Mk2 and EUR 0.21 per litre for Mk3. Additionally, a CO_2 tax is levied at a constant rate for all three classifications, at EUR 0.33 per litre. At the same time, motor gasoline has an energy tax of EUR 0.34 per litre and a CO_2 tax of EUR 0.27 per litre.

Figure 4.25.5 Refinery output vs. demand, 2012



Ports and pipelines

Sweden has three main ports for importing crude oil and the refinery feedstocks necessary to supply the country's refineries. The combined total capacity of these ports is roughly 450 kb/d, with the individual port capacities commensurate with the capacities of the refineries they serve.

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Imports of refined products flow primarily through six main ports, three of which are in the Stockholm area. The six ports have a total combined capacity to import over 190 kb/d of refined products.

Because of Sweden's small market and sparse population, the oil distribution infrastructure relies on road distribution rather than pipelines. Around 800 road tankers carry out secondary distribution to consumers and retail outlets.

Storage capacity

Sweden has approximately 30 coastal and inland storage facilities with a combined total oil storage capacity of 15.2 million cubic metres (mcm), or nearly 96 million barrels (mb). Major depots are located in Göteborg, Lysekil, Gävle, Stockholm, Norrköping and Malmö, with a total storage capacity of nearly 65 mb (10.3 mcm). These facilities play an important role in the domestic distribution of oil products from domestic refineries and import terminals. The remaining storage capacity (31 mb) is spread over 22 storage sites located around the country.

Decision-making structure

The Minister of Enterprise, Energy, and Communications is responsible for oil and natural gas emergency policy in Sweden. The Swedish government states that its energy policy should be built on the same foundations as wider energy co-operation in the European Union, i.e. ecological sustainability, competitiveness and security of supply. It considers its key areas of work to be security of supply, improving the efficiency of energy use, promoting renewable energy and efficient energy technology.

Sweden's response to an oil supply crisis would be the lowering of the compulsory stockholding requirements set on industry. Specific demand restraint measures have not been prepared and would not be part of an initial response. However in a severe and long-lasting crisis, Swedish authorities would likely consider light-handed measures to supplement the use of compulsory industry stocks.

The SEA, under the Ministry of Enterprise, Energy and Communications, has the main responsibility for emergency response. Within the agency, the Central Office of Security of Energy Supply team is the core of Sweden's national emergency strategy organisation (NESO). In normal times, 12 to 15 people work in the core NESO; this can be expanded in times of crisis to include relevant expert staff from both inside and outside the SEA. Close co-operation with industry is a key element in the Swedish NESO and the industry is represented in the regular work of the NESO by the SPBI. Other players, such as independent oil consultants and institute researchers, interact with the NESO team when appropriate.

During a crisis, the NESO would analyse the situation and provide recommendations to the Ministry of Enterprise, Energy and Communications regarding possible response measures. In the case of an IEA collective action, ministry officials would consult with the energy minister and, based on the outcome, draft a formal decision to be adopted by the government at its weekly meeting, or potentially at an extraordinary meeting of ministers. Once approved, the SEA would be responsible for immediate implementation of the agreed response plan.

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Stocks

Stockholding structure

Sweden meets its stockholding requirements to both the IEA and the European Union by placing compulsory stockholding obligation (CSO) on oil industry participants. Compulsory stocks are commingled with commercial and operational stocks.

Sweden bases the industry CSO on deliveries to the domestic market of the main refined product categories (i.e. motor gasoline, kerosene, diesel and fuel oils). In addition to importers and domestic refiners, major consumers of these fuels (defined as consuming annually over 50 000 m^3 or roughly 314 kb), such as manufacturers and CHP plants, are subject to the stockholding requirement.

Crude or products

Subject to approval from the SEA, companies can meet their CSO for oil products with substitution by either crude oil or another product (when this is determined by the SEA to provide the same level of security).

Location and availability

Ticket arrangements are allowed, both domestic and abroad, according to specific rules set out in SEA regulations. Such arrangements must be granted by the agency beforehand and formalised by a contract covering a period of no less than three months and no more than one year. Bilateral agreements for stockholding abroad are subject to a maximum of 30% of an organisation's total stockholding requirement for each stock category. Sweden has formal bilateral agreements with Denmark, Estonia, Finland, Ireland, the Netherlands and the United Kingdom. Stocks held in those countries on behalf of a Swedish company must be owned by the Swedish company or by a company in the country involved.

Total stocks in Sweden at the end of 2012 were 28 mb. This figure includes some 3.6 mb of oil held by major consumers to meet their CSOs.

Monitoring and non-compliance

Companies subject to CSOs must report monthly to the SEA, indicating the amount of fuel stocks held at the end of the previous month, as well as their location and method of storage. The SEA is entitled to inspect the stocks held under the obligations, and can also examine the accounts and other documents relating to company stockholding operations.

Any company failing to maintain compulsory stocks must pay the state a special storage penalty charge. This penalty charge corresponds to the estimated capital cost of the product for one month, plus a surcharge of 60% for failing to meet the requirement.

Stock drawdown and timeframe

The authority to alter the industry stockholding obligation rests with the Swedish government. This would be a decision taken by all ministers, based on a draft government decision presented by the energy minister, either at a regularly scheduled weekly meeting or potentially at an extraordinary meeting of ministers. Depending on the circumstances, a government decision on whether to authorise the lowering of the CSO can be expected to take 7 to 14 days.

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Immediately following the government decision, the SEA would decide the maximum stock draw of relevant stocks for each company as well as other specific conditions. The government and agency decisions would normally be distributed to oil companies the same day. Each individual company would be left to make the commercial decisions on how to deal with the volumes of oil no longer bound by stockholding obligations.

Financing and fees

No financial support is given to oil companies or large consumers which are subject to compulsory stockholding obligations. Thus costs are implicitly passed on to final consumers in market prices.

Other measures

Demand restraint

In a severe and long-lasting crisis, Swedish authorities would likely consider light-handed measures to supplement the use of compulsory industry stocks. The SEA would advise the government on possible measures to be implemented in the crisis while the government would take the final decision on the measures deemed appropriate. The SEA has the overall responsibility for the implementation of energy demand restraint measures, with the 2007 Ordinance (2007:1153) serving as the legal basis. This provides the SEA with the ability to implement a variety of light-handed demand restraint measures. Stronger measures such as rationing would first require parliamentary approval.

In a crisis, Swedish authorities would begin by focusing on an information campaign to encourage oil saving, while assigning fuel savings to all governmental agencies in order to set an example for the general public. Administrative instruments, such as speed reductions and Sunday driving bans, could be used in order to strengthen demand restraint measures. Economic instruments, such as modifying fuel taxes or subsidising alternative travelling options, could also be contemplated, while a rationing system would be considered as a policy option of last resort.

As in other IEA countries, the transport sector makes up the single largest share of oil consumption in Sweden and would therefore be the most likely sector to be targeted for demand restraint measures.

Fuel switching

Short-term fuel-switching capacity in Sweden is considered inconsequential and there are no incentives or policy options to incite such switching in an oil crisis. Sweden uses only a small portion of its oil for power generation. In instances where oil is used, this is primarily for peak production hours and when regular power production is shut down. In the case of an oil crisis, no environmental regulations would be altered to allow for greater use of fuel switching.

Other

With no domestic production, short-term surge production is nonexistent in Sweden.

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Gas

Market features and key issues

Gas production and reserves

Sweden has no indigenous production of natural gas.

Gas demand

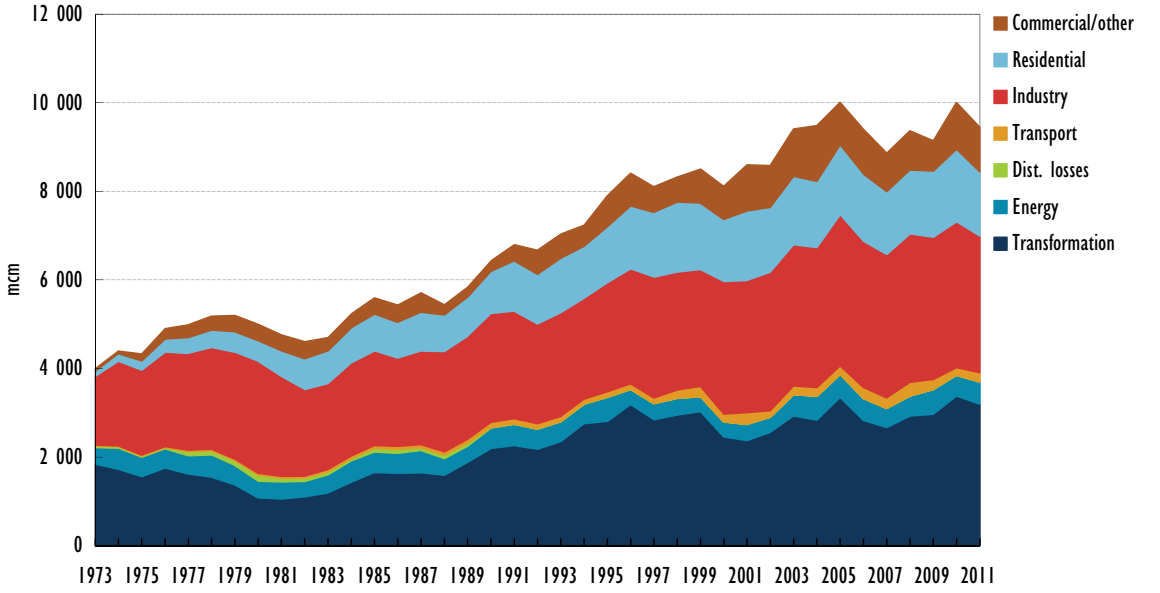
Domestic gas consumption in Sweden totalled around 1.3 bcm in 2011, compared to over 1.5 bcm in 2010, a consumption peak year. In 2011, 43% of total gas use was consumed in the transformation sector and 37% in the industry sector, which includes non-energy use. The residential and commercial sectors each accounted for another 6% and 10% respectively, while the remainder of gas use was in the transport sector (4%).

Natural gas plays only a minor role in Sweden's energy supply; in 2012 it represented 2% of TPES and only 1% of total electricity generation. However, the role of natural gas in the energy supply of southern and western Sweden is much more substantial. In the 30 municipalities in Sweden which have access to natural gas supplies, natural gas accounts for around 20% of total energy use on average.

Roughly 80% of total gas use is consumed by 30 large consumers. This includes nine cogeneration plants (CHP for district heating) which account for 55% of all gas use in the country. Around 2% of total gas use in Sweden is by smaller consumers (i.e. households); these are considered protected customers and number around 33 000 consumers.

Sweden's daily gas consumption typically ranges between 6 and 7 million mcm/d in the winter, compared to around 1.2 mcm/d in the summer. On the basis of the European standard of a 1-in-20 year exceptional cold winter causing peak demand, Sweden's maximum daily gas demand is calculated at 7.8 mcm.

Figure 4.25.6 Natural gas consumption by sector 1973-2011



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Gas import dependency

Sweden has no indigenous production of natural gas and is thus 100% import dependent. All natural gas supplies come from Denmark via a single interconnector in the southwest of the country. As Sweden is at the end of the gas supply line from Denmark, there is no transit of natural gas through Sweden.

Gas company operations

The company Swedegas is the owner and operator of the transmission system and storage facility, as well as being responsible for maintaining physical balance within the system.

There are five distribution system operators (DSOs) in Sweden, the largest being E.ON Gas Sverige. There are only five traders selling natural gas for use in the Swedish gas network. The largest players are DONG, E.ON Försäljning Sverige and Göteborg Energi. The Swedish gas market requires that at each withdrawal point there be a party that has financial liability for ensuring that the gas system is balanced. Typically, it is the traders who are responsible for balancing the gas, but traders may also buy this service from others. There are four balance-responsible parties for the Swedish market: E.ON Gashandel, DONG Energy, Göteborg Energi and Modity Energy Trading AB.

Gas supply infrastructure

Ports and pipelines

The Swedish transmission system for natural gas begins at Dragør in Denmark, crosses the Öresund via the Öresund pipeline to Klagshamn south of Malmö, from where the trunk pipeline heads northward to Stenungsund. The technical capacity of the Öresund trunk line is 8.4 mcm/d while the technical capacity of the entry point of Dragør is 7.8 mcm/d.

The Swedish natural gas network consists of approximately 620 km of transmission lines and roughly 26 000 km of distribution lines. Branch pipes lead off from the trunk pipeline to various consumption areas. There are 39 metering and control (MC) stations connected to the branch lines, where the gas is metered and the pressure reduced. Local distribution systems are then connected to the MC stations. These systems distribute the gas to the end consumers.

The terminal at Nynäshamn, south of Stockholm, receives liquefied natural gas (LNG) and has been in operation since mid-2011. This port has a maximum capacity to supply 6 mcm/d; however it is not connected to the gas transmission system in the southwest of Sweden.

Storage

There is only one small storage facility in Sweden which is used for meeting peak demand. Located at Skallen, in southern Halland, it is a lined rock cavern with a total working capacity of 8.8 mcm and a maximum withdrawal capacity which varies from 0.6 to 0.9 mcm/d, a variation which depends on the pressure in the storage facility and the trunk pipeline. The withdrawal capacity corresponds to 10% to 20% of the gas requirement of the Swedish market under winter conditions.

Sweden has no storage to provide for seasonal swings in natural gas demand. This is primarily provided for with the assistance of storage facilities in Denmark (at Stenlille).

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Emergency policy

Swedish emergency response policy for natural gas is based on the European Regulation No 994/2010. The 2005 Natural Gas Act gives powers to the system-balancing authority to order system operators to increase or reduce the input or off-take of gas flows and to restrict or discontinue the transmission of natural gas to customers. This provides the statutory powers for physically balancing the domestic gas network in times of crisis.

The 2006 Natural Gas Ordinance establishes responsibilities under the Natural Gas Act. Since 2013, the role of system-balancing authority has been appointed to the TSO, Swedegas.

The Natural Gas Ordinance also sets the circumstances under which supplies to protected customers are to be safeguarded. This is defined as being in at least the following cases: a partial disruption of supplies for up to 24 hours; disruption of supplies during the winter period (running from the beginning of December to the end of February); and disruption during periods when temperatures are 4°C to 5°C less than the normal winter temperatures (1 in 20 winters).

Sweden defines protected customers as all households and small consumers connected to the gas distribution network. Approximately 33 000 customers fall under this definition and collectively these consumers account for 2% of total natural gas consumption in Sweden.

Emergency response measures

Means for responding in a crisis include the use of line pack, maximising the input of biogas supplies into the network, and drawing on available volumes in storage. Swedish authorities estimate that these measures could maintain supplies to the entire Swedish gas market during a total cut-off lasting less than 24 hours during high demand. However, disconnecting large users of natural gas remains the most important way of safeguarding supplies to protected customers in a gas crisis. In this case, supplies to protected customers are estimated to be maintainable for one month in the case of high demand, and for several months in the case of low demand.

A total of about 60 large natural gas consumers can potentially be cut off from supplies very rapidly in an emergency, the equivalent of nearly 85% of total gas demand in Sweden. Large CHP units, which constitute almost half of all gas demand in Sweden, have the capacity to quickly switch from natural gas to gasoil. Large industries, representing another quarter of total gas demand, also have the capacity to switch to other fuels, primarily fuel oil. There are no requirements for gas users with fuel-switching capability to keep specific stocks of alternative fuels.

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Switzerland

Key data

Table 4.26.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Demand (kb/d)	268.1	274.0	271.3	265.6	246.6	249.9	249.4
Motor gasoline	86.2	92.0	83.2	73.3	70.5	67.6	-
Gas/diesel oil	131.1	125.1	139.0	139.5	121.9	129.7	-
Residual fuel oil	9.3	3.6	2.5	1.4	1.0	1.2	-
Others	41.6	53.3	46.6	51.5	53.2	51.3	-
Net imports (kb/d)	268.1	274.0	271.3	265.6	246.6	249.9	249.4
Import dependency (%)	100	100	100	100	100	100	100
Refining capacity (kb/d)	132.0	132.0	132.0	134.7	134.7	134.7	-
Oil in TPES (%)**	50	43	45	40	39	39	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.26.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	4	0	0	0	0	0	0
Demand (mcm/y)	1 994	2 972	3 399	3 682	3 269	3 584	3 333
Transformation	150	274	295	286	242	0	-
Industry	704	849	937	1 042	1 001	0	-
Residential	729	1 043	1 242	1 410	1 188	0	-
Others	411	806	925	944	838	0	-
Net imports (mcm/y)	1 990	2 972	3 399	3 682	3 269	3 584	3 333
Import dependency (%)	99.8	100	100	100	100	100	100
Natural gas in TPES (%)	7	9	11	12	11	11	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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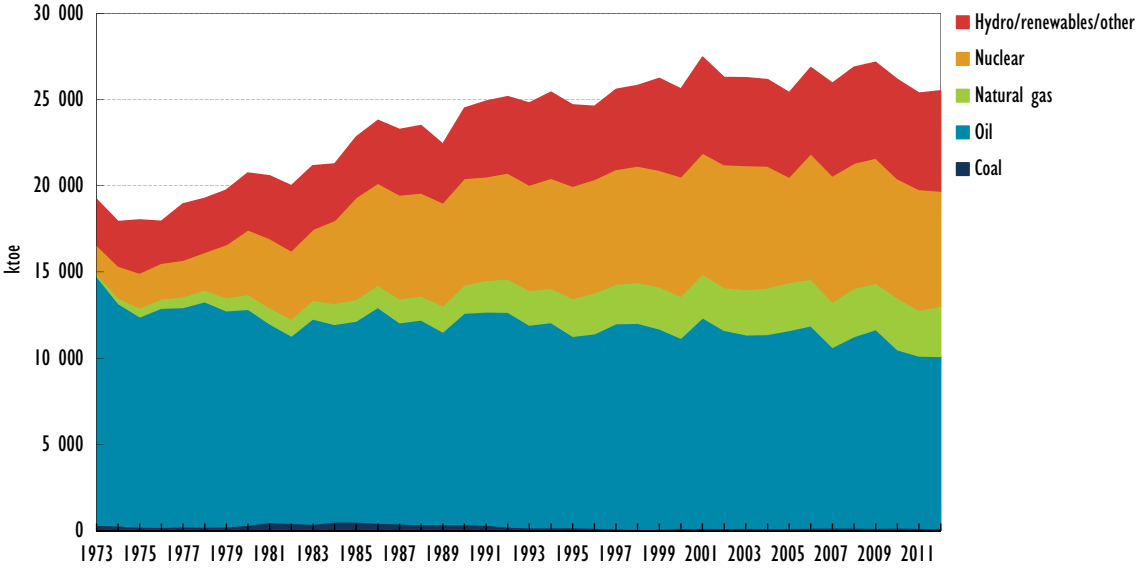
Figure 4.26.1 Total primary energy source (TPES) trend, 1973-2012



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Map 4.26.1 Oil infrastructure of Switzerland

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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Map 4.26.2 Gas infrastructure of Switzerland

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Country overview

Oil has been a dominant energy source in Switzerland, accounting for 39% of the country's total primary energy supply (TPES) in 2012. Switzerland's oil demand has decreased from 277 thousand barrels per day (kb/d) in 2000 to 250 kb/d in 2012. The transport sector accounted for about 60% of total oil consumption in 2011.

As Switzerland has no domestic oil production, it is entirely dependent upon crude oil and oil product imports. In 2012, its oil imports were around 244 kb/d, consisting of 68 kb/d of crude oil, 1 kb/d of natural gas liquids (NGLs) and feedstock and 174 kb/d of refined products. While half of total crude oil imports came from Libya in 2012, almost all refined product imports came from OECD Europe countries, primarily from Germany (50% of the total).

Switzerland meets its stockholding obligation to the International Energy Agency (IEA) by placing a stockholding obligation on industry. Oil product importers are obliged to hold at least 4.5 months of stocks for motor gasoline, diesel and heating oils and 3 months for jet fuels, based on their 3-year average share in imports or sales, depending on products.

Switzerland held 36 million barrels (mb) of industry stocks at the end of April 2013, equal to 156 days of 2012 net imports. All oil stocks are held in the form of oil products, and are commingled with commercial stocks.

The use of emergency oil stocks is central to Switzerland's emergency response policy, which can be complemented by demand restraint measures. In an IEA co-ordinated action, the government would participate with the release of compulsory stocks.

The share of natural gas in the country's TPES stood at 11.5% in 2012. Switzerland's gas demand increased from 3.0 bcm in 2000 to 3.6 bcm, or 9.8 million cubic metres per day (mcm/d), in 2012. As Switzerland has no natural gas production, all its gas demand is met by imports through pipelines.

The key elements of Switzerland's overall gas security policy are compulsory stocks for dual-fuel gas installations in the form of heating oil for fuel switching, an allocation scheme for large consumers and demand restraint measures. Switzerland obliges all gas importers to hold compulsory stocks in the form of natural gas or heating oil, or to participate in building such stocks. The equivalent of 4.5 months of natural gas consumption of dual-fuel gas installations is held in the form of heating oil stocks.

In the event of a gas supply disruption, the Swiss Federal Council can oblige dual-fuel gas consumers to switch gas to fuel oils. Dual-fuel gas installations account for roughly one-third of total natural gas consumption in Switzerland. To prepare for a situation in which fuel switching is not sufficient to compensate for a gas supply shortfall, the government will implement an allocation scheme for non-switchable large consumers.

Oil

Market features and key issues

Domestic oil production

Switzerland has no domestic production of crude oil and Swiss oil demand is fully covered by imports.

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Oil demand

The country's oil demand has decreased by around 10% from 277 kb/d in 2001 to 250 kb/d in 2012. In 2011, 60% of total Swiss oil demand was consumed in the transport sector, while the residential sector accounted for 19% and the industry sector accounted for 10%.

Figure 4.26.2 Oil consumption by sector, 1973-2011

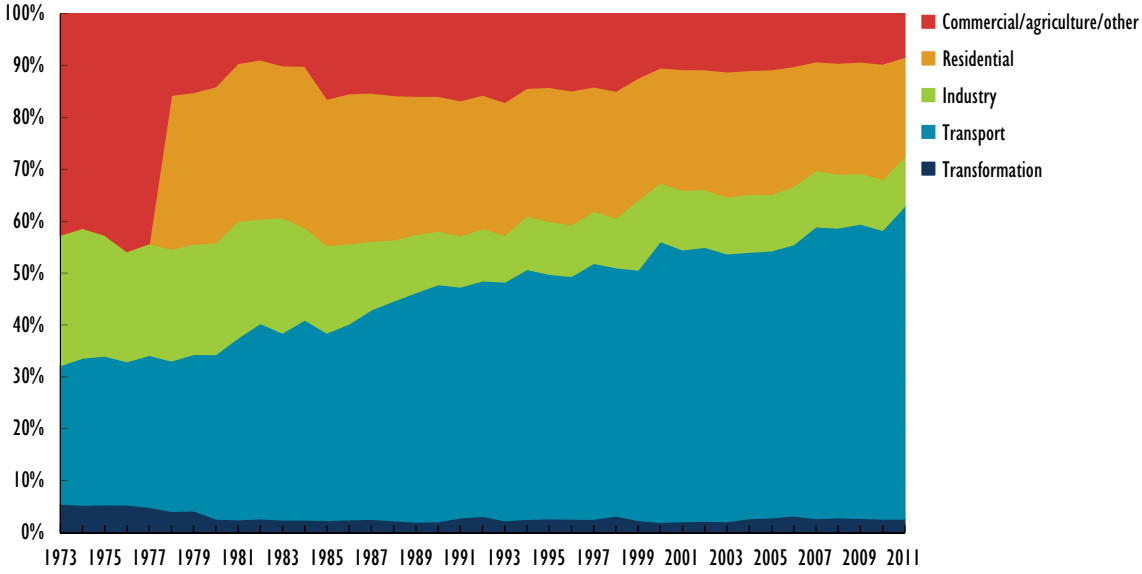
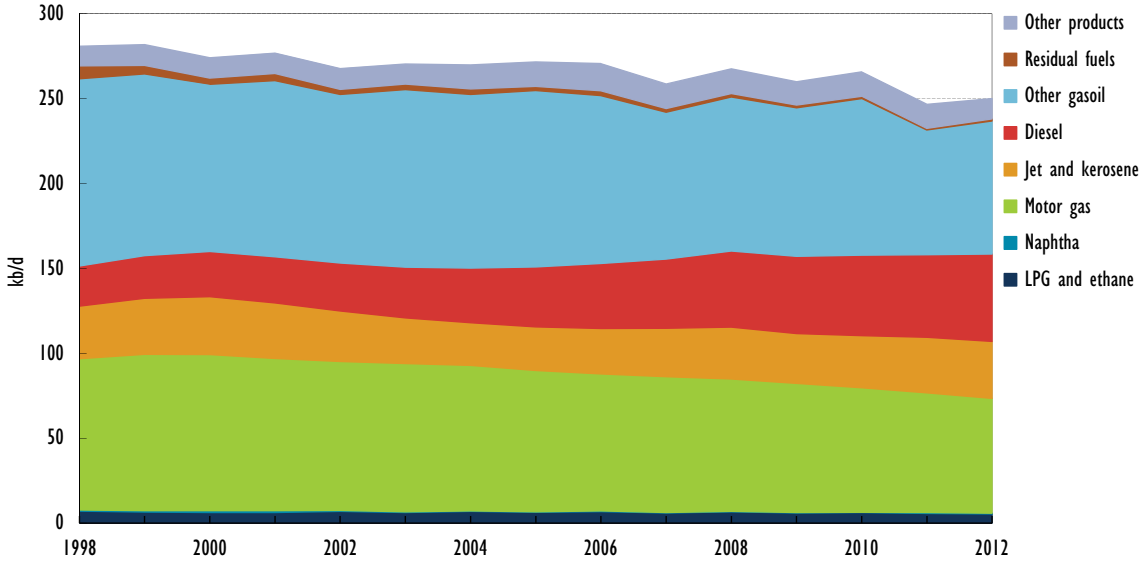


Figure 4.26.3 Oil demand by product, 1998-2012



In terms of oil demand by product, between 2003 and 2012 demand for diesel increased substantially by some 72%, whereas demand for gasoline decreased by 23% during the same period. Demand for heating oil/other gasoil also dropped by 25%. Demand for jet and kerosene increased from 25 kb/d in 2005 to 34 kb/d in 2012 and, according to the government, this upward trend is estimated to continue.

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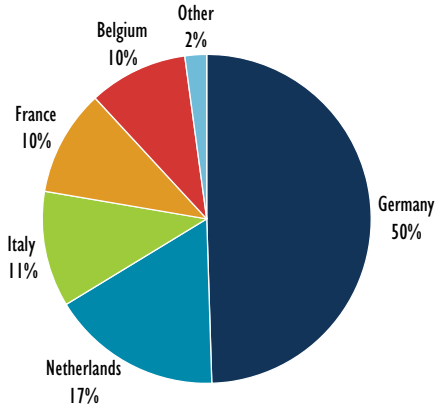
The 5-year forecast of CARBURA, Switzerland's stockholding organisation, indicates that total demand for oil products will decrease by 4% in 2016 compared to 2011, although demand for transport diesel and jet fuel will increase by 11% and 7% respectively. The decline of total demand stems from the gradual decrease in demand for motor gasoline and heating oil.

Imports/exports and import dependency

Switzerland's oil imports in 2012 were some 244 kb/d, consisting of about 68 kb/d of crude oil, 1 kb/d of NGLs and feedstock, and some 174 kb/d of refined products.

Figure 4.26.4 Oil products imports by origin, 2012



Libya was Switzerland's largest supply source of crude oil in 2012, amounting to half of total crude oil imports, followed by Kazakhstan (21%), Nigeria (19%) and Algeria (6%). In the same year, almost all refined product imports came from OECD Europe countries, namely from Germany (50% of the total), the Netherlands (17%), Italy (11%), France (10%) and Belgium (10%).

Oil company operations

The number of importers significantly decreased from 1990 (88 importers) to 2012 (60 importers). Among the 60 importers, the seven major importers (BP Switzerland, Total Suisse, Socar Energy Switzerland, Shell Switzerland, Tamoil, Migrol and Varo Energy) supplied around two-thirds of total imports in 2012.

Oil supply infrastructure

Refining

There are two refineries in Switzerland, with a total crude distillation capacity of around 125 kb/d. The Cressier refinery, operated by Varo Energy, has a crude distillation capacity of 68 kb/d. Crude oil supply arrives through the South European Pipeline System (SPSE) from the marine shipping terminal in Fos-sur-Mer in the south of France. The other refinery is the Collombey refinery operated by Tamoil, whose crude distillation capacity is 57 kb/d. Crude oil arrives from the Port of Genoa, Italy, through a pipeline crossing the Alps.

In 2012, the refined product output from the two domestic refineries totalled 73.1 kb/d. This is considerably lower than the level of the previous year which amounted to 94.8 kb/d. This fall in output was because the Cressier refinery had been shut down

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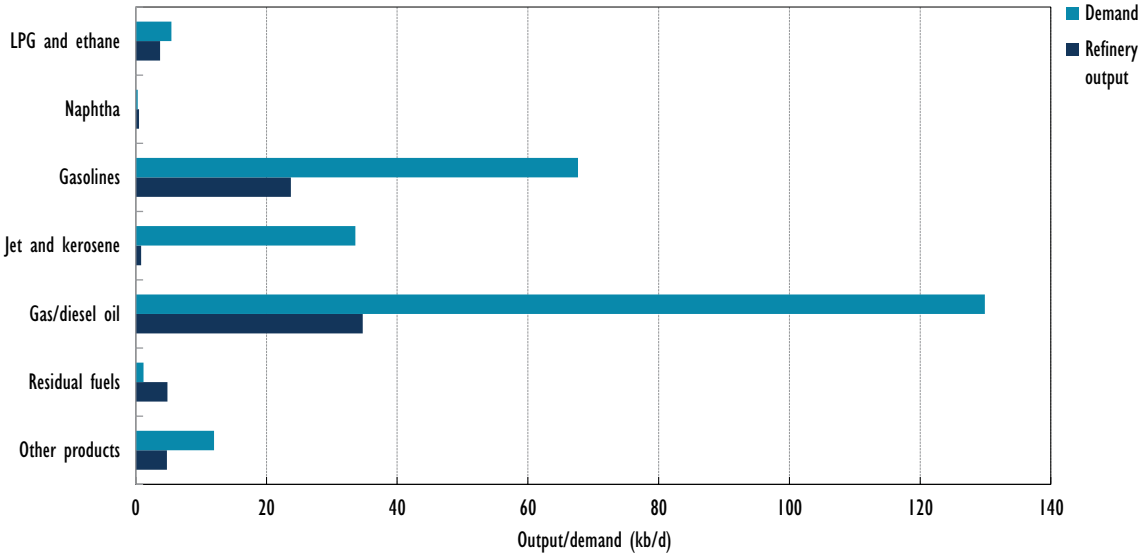
since January 2012 owing to the previous owner's (Petroplus) limited credit availability to ensure its proper operation. In May 2012, Varo Energy agreed to purchase the assets of Petroplus in Switzerland, and the transaction was completed in June 2012.

Figure 4.26.5 Refinery output vs. demand, 2012



In 2012, the composition of production from these refineries was gas/diesel oil (48%), gasoline (32%), residual fuel oil (7%) and liquefied petroleum gas (6%).

With the exception of residual fuels, domestic refinery production is not sufficient to meet demand in the country. In 2012, domestic production of gas/diesel oil was able to meet some 28% of domestic demand, while gasoline production amounted to around 34%, requiring imports to meet the remaining share.

Ports and pipelines

The imports of crude oil and petroleum products are mainly carried out by pipelines, rail tank cars and Rhine barges. Among these transport means, pipelines play the most important role, sharing over 35% of total oil imports in 2012.

Switzerland has one pipeline for oil products and two pipelines for crude oil. The SAPPRO pipeline, with an authorised capacity of around 30.3 kb/d (1.5 Mt per year), connects with the French SPMR pipeline coming from Fos-Lavera at Saint-Julien-en-Genevois. This pipeline supplies diesel, heating oil, gasoline and kerosene to terminals and tank farms in Geneva. The network runs around 12 km in Switzerland.

Concerning crude oil pipelines, the Oléoduc du Rhône runs from Genoa, Italy, to the Collombey refinery. This pipeline's capacity is approximately 61 kb/d (3 Mt per year). Another crude pipeline is the Oléoduc du Jura Neuchâtelois, branched off from the SPSE pipeline at Gennes in France. This pipeline, with a capacity of 91 kb/d or 4.5 Mt per year, is connected to the Cressier refinery.

There is no oil sea port in Switzerland, but there are three oil ports in Basel to ship oil products on the Rhine by barge; 2.3 Mt (around 47 kb/d) of oil products were unloaded in 2011.

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Storage capacity

Switzerland has a total storage capacity of about 49.1 mb (or 7.8 mcm), which is mostly used for compulsory industry stocks (33.7 mb or 5.4 mcm). The oil industry has 72 above-ground tank farms, spread over the country, but mostly located around the areas of high population density between Geneva and Lake Constance. Storage capacity has been reduced over the past 15 years because of the lowered level of compulsory stocks, as well as the decline in oil consumption.

Decision-making structure

The Federal Department of Economic Affairs, Education and Research (EAER), comprising the Federal Office for National Economic Supply (FONES), is responsible for short-term energy security. The Swiss national emergency strategy organisation (NESO) is established on a stand-by basis and combines government authority for national oil and gas emergency management (mainly FONES) with expertise of domestic oil and gas industry experts. The federal government assigns a Delegate for National Economic Supply to manage the NESO which is responsible for strategic planning and co-ordination of all activities regarding Switzerland's security of supply. While the Delegate reports to the head of the EAER, the delegate must be chosen from the private sector and is also required to continue their work in the private sector to guarantee a strong co-operation between industry and governmental authorities.

The main body of the Swiss NESO is the Basic Supply Unit "Energy", in which the administration works closely with external experts designated by the Delegate for National Economic Supply. The FONES acts as a permanent secretariat of the NESO in providing necessary assistance to manage legal issues and to facilitate the work of external experts. Active participation from the industry is assured for smooth and efficient co-ordination during a supply disruption.

During oil supply disruptions, the Oil Products Division of the Energy Unit has the leading role in co-ordinating the NESO and maintaining liaison with industry regarding emergency response.

In practice, the Energy Unit assesses emergency situations in co-operation with CARBURA, the stockholding organisation, and government authorities such as the State Secretariat for Economic Affairs (SECO) and the Swiss Federal Office of Energy (SFOE). The assessment will be presented to the Delegate for National Economic Supply together with the necessary response plans to be implemented. The delegate will decide whether the plan should be put forward to senior authorities. Compulsory stock release will be decided by the head of EAER based on the report of the Delegate, while demand restraint measures will be decided by the Federal Council.

Stocks

Stockholding structure

Switzerland meets its stockholding obligation to the IEA by placing a stockholding obligation on industry, which dates back to 1938 and thus precedes the International Energy Program (IEP) Agreement of 1974. Switzerland has no public stocks or public stockholding agency. In the event of an emergency, the head of the EAER has the power to allow oil importers to release their obligated stocks into the market, based on a recommendation of the Delegate for National Economic Supply.

All oil importers are required to hold a certain amount of stocks according to their import/sales share. They are obliged to hold at least 4.5 months of stocks for motor

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gasoline, diesel and heating oils and 3 months for jet fuels. Stocks of motor gasoline and of heating oil are calculated based on a 3-year average of import shares, while stocks of diesel and of jet fuel are based on a 3-year average of sales shares. The levels of stock obligation are set by a directive of the EAER.

All oil importers are also required to become a member of the stockholding organisation, CARBURA. CARBURA is an industry organisation which co-ordinates the implementation of the obligation of importers and other stockholders. CARBURA is mandated by the administration to issue import licences and by its members to manage guarantee funds, pay compensation to stockholders for stockpiling costs and collect statistical data. On behalf of the FONES, CARBURA is tasked to verify the physical stock levels of each stockholder. The FONES has legal authority to penalise non-compliant companies.

Crude or products

Switzerland held some 36 mb of industry stocks at the end of April 2013, equal to 156 days of 2012 net imports. About 64% of total industry stocks were stored as middle distillates, while the share of motor gasoline was 32%. All oil stocks are held in the form of oil products, as there is no crude oil stockholding obligation in Switzerland.

Location and availability

Switzerland has no bilateral agreements to hold stocks on foreign territory. Emergency oil stocks are held entirely on the national territory of Switzerland.

Although every importer has an individual target of 4.5 months of import/sales share (3 months for jet fuels), it is allowed to deviate from this target in a range between 2.2 to 9 months of individual coverage. Importers can delegate up to 50% of their individual obligation to a substitute stockholder. As oil importers have flexibility in the size of their stocks, a Common Stockholder, which is owned by CARBURA, makes up the difference between the overall obligation on industry and the sum of stocks held by importers and substitute stockholders.

As compulsory stocks are usually commingled with commercial stocks and they are obliged to be reported on top of minimum operating requirements (MOR), the issue of MOR is considered to have no impact on the level of emergency stocks in the country.

Monitoring and non–compliance

CARBURA conducts regular on-site audits to monitor the physical availability and quality of compulsory stocks. The FONES has the legal authority to penalise non-compliant companies, including fines up to EUR 83 000 and prison sentences. In the event of material violations, the oil import licence can be withdrawn.

Stock drawdown and timeframe

Swiss compulsory stocks will be released company by company, taking into account their respective supply and delivery obligations. Oil companies will be entitled to make a request for stock release by each product. Based on such a request, the compulsory stock release will be calculated according to the concrete loss of supply of the company concerned. Less than 10-15 days are required to make compulsory stocks available to the market. Price tenders or loans are not permitted.

If the country should commit to international obligation for international supply disruptions which do not influence the domestic market, the FONES will offer all oil importers the opportunity to draw down stocks voluntarily. In case no oil importer takes up this opportunity, the FONES assigns a quota per company based on its import share.

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Financing and fees

Switzerland's compulsory system is based on the notion that oil companies should not bear the financial burden resulting from their obligation to maintain stocks. Therefore, compulsory stock costs are financed by levies imposed on the import of oil products which CARBURA collects from oil companies and puts into the "Guarantee Fund". The fund compensates for the stockholding expenses of stockholders. The purchase of oil products stored as compulsory stocks is financed through the CARBURA Guarantee Fund by means of an amortisation system. The collection of import fees amounts to about EUR 50 million per year.

Other measures

Demand restraint

Demand restraint is regarded as a secondary emergency response measure to complement the release of compulsory stocks in case of severe oil supply disruptions which last longer than six months. With this approach, there would be enough time to prepare, decide upon and implement demand restraint measures, such as a *pro rata* allocation system for heating oil (Ordinance on Heating Oil Regulation) and a rationing system for transport fuels (Ordinance on Rationing Transport Fuels). Light-handed measures such as speed limits and Sunday driving bans can be introduced in combination with a stock release.

The Federal Council will make a decision on demand restraint measures, based on a recommendation by the Delegate for National Economic Supply. Switzerland's demand restraint measures would range from light-handed measures (e.g. appeals for self-restraint, speed limits, promotion of carpooling, and Sunday driving bans), to heavy-handed measures (e.g. a *pro rata* allocation scheme for heating oil and a rationing scheme for transport fuels such as gasoline and diesel).

The country has developed a coupon system for fuel allocation for a period of two months. Cantons will distribute coupons according to the licensed car number plates, which allow the owners of licensed cars to buy a uniform quantity of fuel depending on the type of vehicle.

In case of activation of the allocation scheme for heating oil, consumers will be required to have a non-transferable purchase certificate based on the individual average consumption in the previous two years.

The allocation scheme for jet fuel aims to reduce jet fuel demand by limiting the amounts of jet fuels at Swiss airports. Airlines will be supplied based on their purchase volume in M-2 month.

Fuel switching

Short-term fuel switching from oil to other fuels is not regarded as an emergency response measure in Switzerland, as the share of oil in power generation was estimated to be only 0.1% in 2012.

Other

As there is no oil production in Switzerland, surge production of oil is not considered an emergency response measure in the country.

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Gas

Market features and key issues

Gas production and reserves

Switzerland has no domestic production of natural gas. Demand for natural gas is fully covered by imports, although the country had little natural gas production in the past.

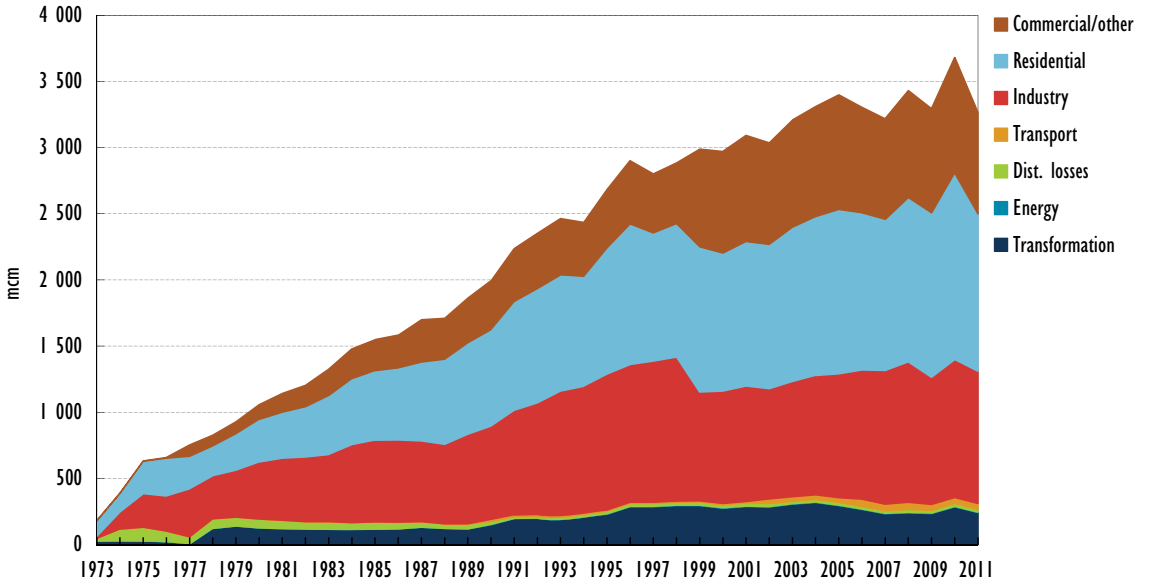
Gas demand

Switzerland's demand for natural gas has increased slightly from some 3 bcm in 2000 to 3.6 bcm (9.8 mcm/d) in 2012.

The residential sector is the largest consumer of natural gas in Switzerland, representing about 36% of the country's total gas consumption in 2011. As such, the supplies of natural gas are of paramount importance in the cold winter months, as many homes depend on gas for residential use and heating. Daily peak gas demand in 2012 stood at some 17.9 mcm/d, which occurred in February. Equally important, the industry sector represented 31% of gas demand in 2011. The commercial and other sectors accounted for 24%.

Future natural gas demand in Switzerland faces uncertainty, as the country has decided to gradually phase out nuclear power plants by the end of their operating life, which is expected to be between 2019 and 2034. In 2012, nuclear power was the second largest source of electricity generation, accounting for 37% of the total, while the share of natural gas as fuel for electricity generation represented only 1.5% of the total.

Figure 4.26.6 Natural gas consumption by sector, 1973-2011



Gas import dependency

Because of the absence of natural gas production, Swiss gas demand is entirely supplied by imports, all arriving by pipeline. Switzerland's total natural gas imports in 2012 amounted to 3.6 bcm. By country, Germany was the largest supplier, representing 62% of

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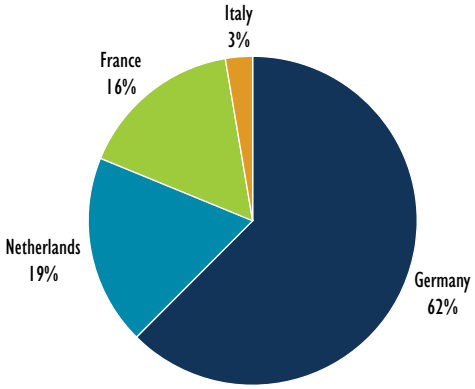
Switzerland's total imports in 2012, followed by the Netherlands (19%), France (16%) and Italy (3%). The share of long-term contracts accounted for around 65% of total imports.

Figure 4.26.7 Natural gas imports by source, 2012



Gas company operations

In 2012, Swissgas AG supplied around 50% of total gas imports, followed by EGO (17%), GVM (14%), Gaznat SA(13%) and AIL (3%).

Within the retail market for gas in Switzerland there are 106 local distributors (mostly public companies) and a few industrial customers. In 2012, the nine largest utilities sold half the total amount of gas. As around 33% of the total gas consumption is covered by interruptible contracts with dual-fired consumers, this amount could be saved in a gas supply disruption.

Gas supply infrastructure

Ports and pipelines

Given that Switzerland is a landlocked country, there is no LNG terminal in Switzerland.

Switzerland's gas pipeline network accounts for about 18 432 km, which includes 2 240 km of high-pressure grid, 4 134 km of middle-range pressure grid and 12 058 km of low-pressure grid. The natural gas grid network covers 69% of the Swiss population.

Although Switzerland has 12 active cross-border feeding points in the European gas pipeline network, some 70% of Switzerland's gas import (around 2.6 bcm/y or 7 mcm/d) comes through the two entry points of the Transitgas pipeline. The total length of this pipeline is 292 km in Switzerland, from Wallbach (51.5 mcm/d maximum technical capacity) on the German border and Oltingue (19.5 mcm/d) on the French border respectively, to Griespass (55.9 mcm/d) on the Italian border. The pipelines are looped from Wallbach to Ruswil. This pipeline is operated by Transitgas AG, which is owned by Swissgas (51%), FluxySwiss (46%) and E.ON Ruhrgas (3%).

The Transitgas pipeline is used to transport natural gas for consumption in Switzerland and for transit from Germany and France to Italy. The annual capacity of this pipeline accounted for 185 terawatt hours (TWh), or around 16.7 bcm. The compressor station in Ruswil has a compression capacity of 60 megawatt hours (MW) and is the operational centre for maintainance and control of the necessary transporting pressure in Switzerland.

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Preparations are underway to enable reversal flow of the Transitgas pipeline from the south (Italy) to the north (Germany and France), which will provide a strong degree of resilience in the event of a gas supply disruption in the north of the country. This project is to be completed in 2015 (partially) and 2018 (fully).

Storage

As Switzerland's gas importers are not required to have a natural gas storage capacity because of the country's geological characteristics, all natural gas storage facilities in Switzerland are in the form of pipelines and spherical storage vessels for daily balancing.

Outside the country, Gaznat SA has a storage capacity in the French underground storage Etrez, which is directly connected to Switzerland's system for the purpose of physically balancing Switzerland's distribution network.

Emergency policy

The key elements of the Swiss gas security policy are a diversified long-term supply contract portfolio for Swiss gas companies, diversified cross-border intake points with connections to the three largest European natural gas markets, compulsory stocks in the form of heating oil for fuel switching, an allocation scheme for large consumers, and demand restraint measures. The Federal Act on National Economic Supply (1982) and the Ordinance 531.215.42 on stock obligation of natural gas (2003) set the standard for gas supply security for suppliers.

All gas importers are required to fulfil their obligation by taking any one of following measures: holding natural gas stocks, holding heating oil stocks, delegating the obligation to hold heating oil stocks to a convenient third party, or participating financially in an existing compulsory stockholding of heating oil.

As a result, the equivalent of 4.5 months of natural gas consumption of dual-fuel gas installations (or roughly 1.5 months of total consumption) is held in the form of heating oil stocks. These heating oil stocks are not categorised as oil emergency stocks.

In case of a gas emergency, the Natural Gas Division in the Energy Unit of the Swiss NESO has the leading role in co-ordinating the necessary action and maintaining liaison with industry. This division will evaluate an emergency situation and propose necessary response measures to the Delegate for National Economic Supply in co-operation with concerned authorities and the gas industry.

Emergency response measures

In the initial stage of a gas emergency, when a shortage of gas supply is anticipated, the first priority is to increase imports from other sources and to switch gas transportation to other unaffected delivery routes.

In case the gas shortfall problem cannot be solved with these measures, the Federal Council can oblige dual-fuel gas consumers to switch from gas to heating oil, based on a recommendation of the Delegate for National Economic Supply. Switzerland has around 4 000 dual-fuel gas installations, mostly used in the industry sector. These dual-fuel units accounted for around one-third of total natural gas consumption.

The fuel-switching measure may be implemented together with the release of compulsory stocks in the form of heating oil, as most dual-fuel gas plants in Switzerland can be run with heating oil. The amount of heating oil stocks for gas emergency is around 400 000 m³ (or about 2.5 mb).

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In case fuel switching is not sufficient to compensate for a gas supply shortfall, the Federal Council may implement an allocation scheme for non-switchable large consumers.

The Federal Council, supported by the gas industry, will apply light-handed demand restraint measures such as appeals to lowering heating temperatures and saving warm water. These measures aim at reducing the gas consumption of small consumers such as households who would not be affected by the abovementioned measures.

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Turkey

Key data

Table 4.27.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	72.5	52.8	43.5	48.3	45.6	44.9	43.4
Demand (kb/d)	477.0	662.8	647.5	649.8	655.3	670.5	745.4
Motor gasoline	74.0	83.6	61.9	47.3	44.9	41.2	-
Gas/diesel oil	153.7	184.8	216.8	300.1	310.8	327.8	-
Residual fuel oil	119.8	141.5	117.8	20.2	18.7	19.8	-
Others	129.6	252.9	251.1	282.3	280.9	281.7	-
Net imports (kb/d)	404.5	610.0	604.0	601.5	609.7	625.6	702.0
Import dependency (%)	84.8	92.0	93.3	92.6	93.0	93.3	94
Refining capacity (kb/d)	725.0	690.9	714.3	630.0	630.0	630.0	-
Oil in TPES (%)**	44	40	34	29	27	27	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.27.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	212	639	897	682	761	632	595
Demand (mcm/y)	3 468	14 835	27 375	38 127	44 686	45 254	59 653
Transformation	2 585	8 845	15 157	20 708	21 570	0	-
Industry	814	2 098	3 839	7 901	9 878	0	-
Residential	49	3 218	5 747	5 888	8 779	0	-
Others	20	674	2 632	3 630	4 459	0	-
Net imports (mcm/y)	3 256	14 196	26 478	37 445	43 925	44 622	59 059
Import dependency (%)	93.9	95.7	96.7	98.2	98.3	98.6	99.0
Natural gas in TPES (%)	5	17	27	30	33	32	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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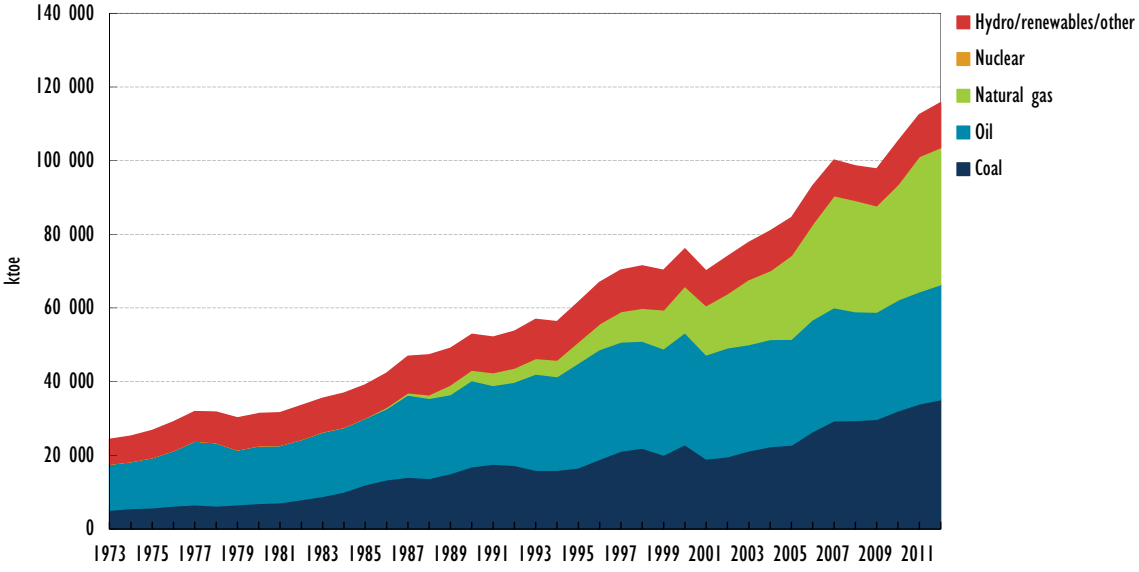
Figure 4.27.1 Total primary energy source (TPES) trend, 1973-2012



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Map 4.27.1 Oil infrastructure of Turkey

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Map 4.27.2 Gas infrastructure of Turkey

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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Country overview

Oil has been one of the main energy sources in Turkey, accounting for 27% of the country's total primary energy supply (TPES) in 2012. Turkey's oil demand increased slightly from 637 thousand barrels per day (kb/d) in 2003 to 670 kb/d in 2012, although in 2009 it dropped down from 678 kb/d to 650 kb/d in 2010. The transport sector accounted for half of total oil consumption in 2011. Domestic oil production is in decline in Turkey, amounting to 45 kb/d or about 7% of total demand in 2012.

In 2012, Turkey imported 712 kb/d, consisting of about 392 kb/d of crude oil and some 320 kb/d of refined products. Iran was the largest supply source of crude oil with 39% of the 2012 total, followed by Iraq (19%), Saudi Arabia (15%) and Russia (11%). Crude oil and petroleum products are mainly delivered by tankers and two major international pipelines running through the country with a total annual handling capacity of 2.8 million barrels per day (mb/d). There are four operational refineries with a total crude distillation capacity of around 610 kb/d in the country.

Turkey meets its 90-day stockholding obligation to the International Energy Agency (IEA) by placing a minimum stockholding obligation on industry. Under the relevant acts, refineries and fuel distribution companies are obliged to hold at least 20 days of product stocks based on the average daily sales of the previous year, while eligible consumers who use more than 20 000 tonnes annually are required to hold 15 days' consumption of each type of liquid fuel.

Turkey held some 63 mb of oil stocks at the end of April 2013. Around 56% of total oil stocks are held in the form of crude oil. The use of emergency oil stocks is central to Turkey's emergency response policy, which can be complemented by demand restraint measures.

The share of natural gas in the country's TPES significantly increased to 32% in 2012. Turkey's gas demand significantly increased from 0.7 bcm (2 mcm/d) in 1987 to 45.3 bcm (124 mcm/d) in 2012, while indigenous natural gas production totalled some 0.63 bcm in the same year. The transformation sector was the largest consumer of natural gas in 2011, representing about 48% of the country's total gas consumption.

The Russian Federation was Turkey's largest supplier, representing 58% of total imports in 2012. Turkey has four international gas pipelines in operation with a total import capacity of some 46.6 bcm, and it plans to diversify its natural gas import pathways by constructing new major cross-border pipelines and liquefied natural gas (LNG) terminals.

Key elements of Turkey's overall gas security policy are diversifying its long-term supply contract portfolio, forming an energy hub from Central Europe and the Middle East to Europe, increasing natural gas storage facilities, cutting back contractual supplies and fuel switching to alternative fuels for power generation. Gas importers are obliged to hold a gas storage capacity corresponding to 10% of their annual gas import. The country has also planned to oblige all power plants with fuel-switching capacity to hold sufficient amounts of secondary fuel such as diesel.

In the event of a crisis, the transmission system operator (TSO), BOTAŞ, would take the lead under the supervision of the Energy Market Regulatory Authority. In case of a gas supply disruption in which the responsible gas suppliers are not identified, the TSO will endeavour to curb gas consumption by reducing the contractual capacities of interruptible contracts and gas-fired power plants which can switch to alternative fuels.

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Oil

Market features and key issues

Domestic oil production

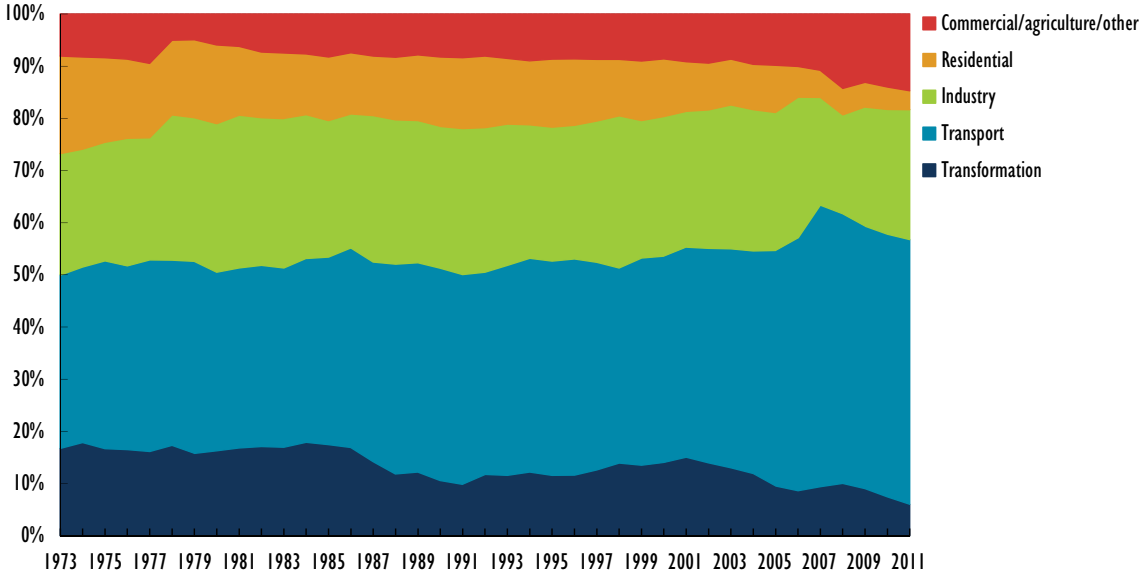
In 2012, Turkey produced 45 kb/d of crude oil; this was equivalent to some 7% of its total consumption. Around 50 upstream companies were granted exploration and production licences in 2012. About 75% of exploration areas are covered by Turkish Petroleum Company (TPAO). The industry estimates that unless new abundant oil fields are discovered, crude oil production will decrease to 12 kb/d by 2030.

Oil demand

Turkey's oil demand slightly increased from 637 kb/d in 2003 to 670 kb/d in 2012, although it dropped from 678 kb/d in 2009 to 650 kb/d in 2010.

In 2011, around 51% of Turkish total oil demand was consumed by the transport sector, while the industry sector and the commercial/agriculture/other sector accounted for 25% and 15% respectively. Relatively high oil demand in the industry sector is driven by the construction sector (around 43% of the industry share) and the chemical sector (23%).

Figure 4.27.2 Oil consumption by sector, 1973-2011



Turkey's demand for diesel almost doubled from 2003 to 2012 whereas demand for gasoline decreased by 34%. Demand for heating oil/other gasoil also increased during the same period. Demand for residual fuels dropped significantly by 86%. The Turkish Petroleum Industry Association (PETDER) forecasts that consumption of gas oil will significantly increase from 2010 to 2020 at a compound annual growth rate of around 3.7%.

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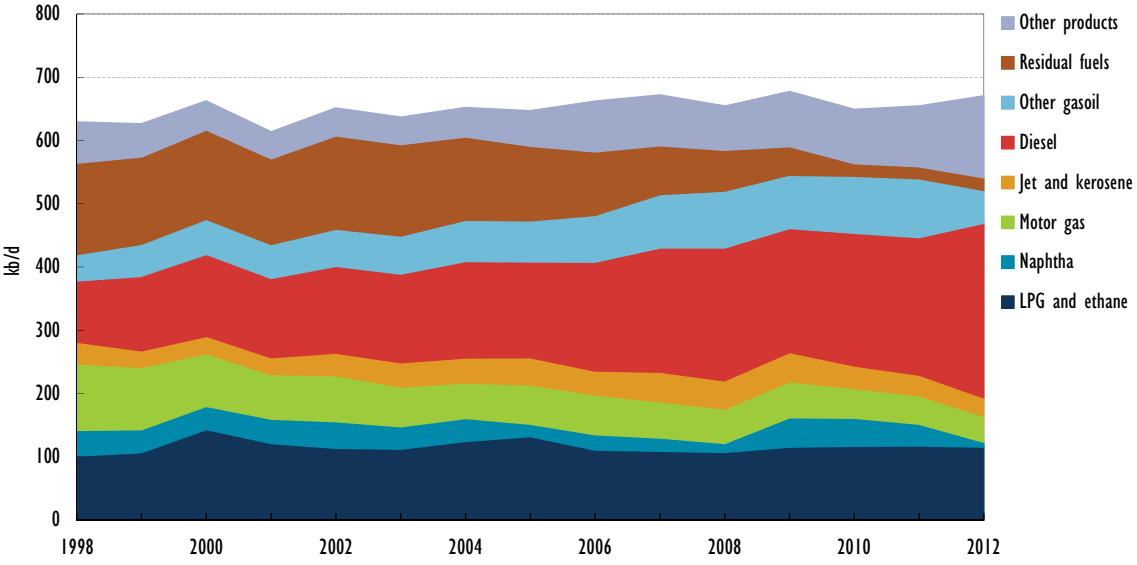
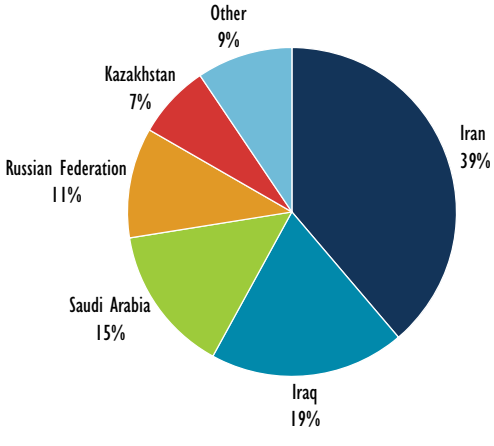
Figure 4.27.3 Oil demand by product, 1998-2012



Imports/exports and import dependency

In 2012, Turkey's oil imports in 2012 were about 712 kb/d, consisting of 392 kb/d of crude oil and 320 kb/d refined products. Iran was the largest supply source of crude oil with 39% of the 2012 total, followed by Iraq (19%), Saudi Arabia (15%) and Russia (11%). In 2012, refined product imports came from Russia (19%), Italy (12%), Greece (9%) and India (8%).

Figure 4.27.4 Crude oil imports by origin, 2012



Oil company operations

TPAO, a state-owned company, is the country's main domestic crude oil producer, covering about 75% of total domestic production in 2011. In 2012, 50 companies were licensed to conduct exploration and production activities. Half of these were foreign-capitalised companies.

TÜPRAŞ, the country's largest industrial company, operates four refineries, while two other refineries are being constructed by Star Refining and Eastern Mediterranean (Doğu Akdeniz) Refinery.

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In 2011, 49 distributors operated 12 441 filling stations in the country. There are also 70 liquefied petroleum gas (LPG) distributing companies running 9 663 LPG autogas stations.

Oil supply infrastructure

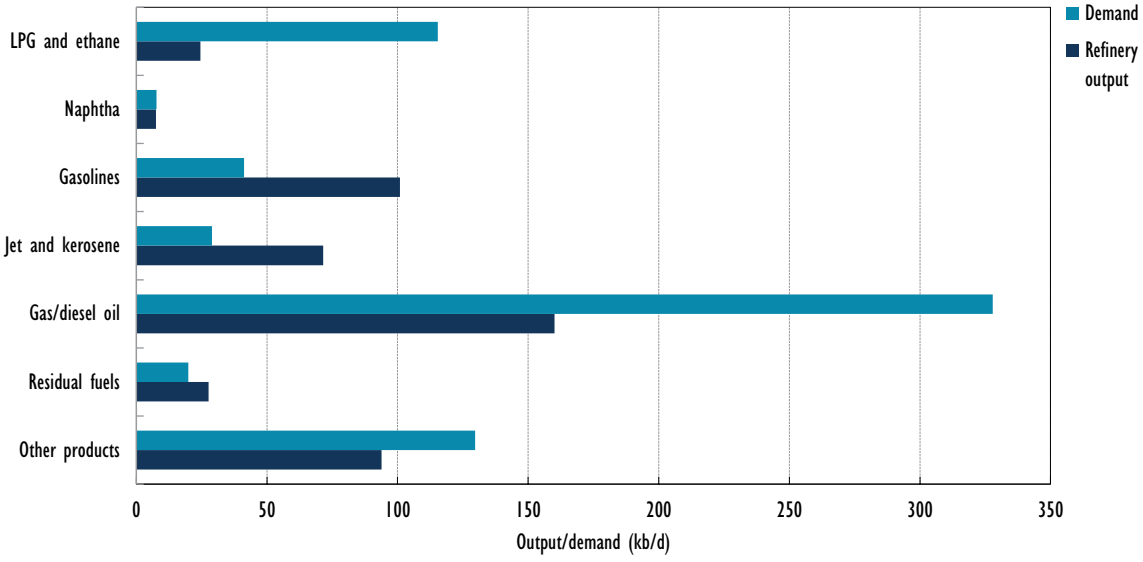
Refining

Turkey's four operating refineries have a total crude distillation capacity of around 610 kb/d. All four are owned by TÜPRAŞ. Three refineries in Izmit, Izmir and Kırıkkale are medium complex refineries, while the Batman Refinery is a simple refinery with atmospheric and vacuum crude units; the refinery is located close to the crude oil production area in southeastern Turkey.

In 2011, TÜPRAŞ processed 13 types of crude oil from nine countries; their gravities ranged between 23 API and 45 API with a sulphur content between 0.6% and 4.1%. Almost 65% of crude oil processed in the country was medium and heavy sour crude in 2011, followed by heavy sour (28%) and light sweet (7%).

Two refineries are under constructionor planned: one refinery in Izmir to be run by Star Refining, is expected to be operational by 2015, while Eastern Mediterranean (Doğu Akdeniz) Refinery is carrying out a feasibility study for another refinery in Adana. When construction of these two refineries is completed, the country's total crude distillation capacity will rise to 1.1 mb/d with a new distillation capacity of around 510 kb/d.

Figure 4.27.5 Refinery output vs. demand, 2012



In 2011, the total crude throughputs averaged 413 kb/d. The total utilisation rate of the four refineries is around 75%: Izmit (82%), Izmir (73%), Kırıkkale (59%) and Batman (86%). In 2012, the refined product output totalled 486 kb/d. The main products of those refineries were gas/diesel oil (33%), which was followed by gasoline (21%), kerosene (15%), residual fuel oil (6%) and LPG (5%).

In 2012 domestic production of gas/diesel oil was able to meet 52% of domestic oil use, while LPG and ethane amounted to some 21% of domestic demand.

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Ports and pipelines

Imports of crude oil and petroleum products are mainly by pipeline and tanker. While Izmit refinery and Izmir refinery import crude oil by tanker, crude oil is delivered to the Kırıkkale Refinery and the Batman Refinery by pipeline.

The country has almost a dozen important oil ports: Antalya, Mersin-Ataş, Trabzon, Hopa, Izmir/Aliağa, Gemlik, Tekirdağ, Izmit, Iskenderun, Zonguldak and Istanbul. In 2011, the country's handling capacity at ports totalled 5.9 mb/d.

Two major international pipelines run through Turkey: Kirkuk-Ceyhan Pipeline and Baku-Tbilisi-Ceyhan Pipeline. There are also three domestic pipelines: Ceyhan-Kırıkkale Crude Oil Pipeline, Batman-Dörtyol Crude Oil Pipeline and Şelmo-Batman Crude Oil Pipeline. The total length of crude oil pipelines in the country is about 3 374 km with a combined handling capacity of about 2.8 mb/d in 2012.

Kirkuk-Ceyhan Crude Oil Pipeline runs from Kirkuk, Iraq, to the Ceyhan Oil Terminal on the Mediterranean Sea and has been active since 1976. A second pipeline parallel to the first was commissioned in 1987, which carries a total maximum annual capacity of 1.4 mb/d. In September 2012, Iraq and Turkey agreed to extend the carriage of Iraqi crude oil import through the pipeline by 15 years. In 2011, this pipeline brought 163.3 mb of crude oil from Iraq to Turkey.

The Baku-Tbilisi-Ceyhan Crude Oil Pipeline has been in operation since 2006. This pipeline carries crude oil from the Caspian region, from Baku to Ceyhan via Georgia. It has a total length of 1 760 km. The original capacity of the pipeline was 1 mb/d, but at present 1.2 mb/d can be transported with the aid of drag-reducing agents. There is also a plan to expand the capacity to 1.6 mb/d. In 2011, this pipeline brought 257.2 mb of crude oil from the Caspian Sea to Turkey.

Among Turkey's domestic pipelines, Ceyhan-Kırıkkale Crude Oil Pipeline has a maximum capacity of 135 kb/d, running from Ceyhan to Kırıkkale Refinery. In 2011, this pipeline carried around 20 mb of crude oil. Batman-Dörtyol Crude Oil Pipeline, with a capacity of 86.4 kb/d, aims to transport crude oil produced in the southeastern Anatolia region to the Dörtyol Marine Terminal. Around 10 mb of crude oil was brought through this pipeline in 2011. The Şelmo-Batman Crude Oil Pipeline has a capacity of 16 kb/d to transport crude oil produced in the Şelmo area to the Batman Terminal; this pipeline has not been in operation since 2008.

Turkey also plans to construct a pipeline from Samsun on the Black Sea to Ceyhan with a capacity of some 1.1 mb/d, which could be expanded to 1.5 mb/d. This pipeline will help to reduce increasing tanker traffic in the Turkish Straits.

Storage capacity

Total storage capacity in Turkey is estimated at some 79 mb (12.5 mcm). Most storage facilities are located in the regions borderning the Sea of Marmara, the Aegean Sea and in Central Anatolia where the refineries are located, as well as in the region bordering the Mediterranean Sea which includes the Ceyhan Oil Terminal. At the end of 2011, around 44% of total storage capacity was owned by TÜPRAŞ, Turkey's largest industrial enterprise, followed by fuel distributors (37%), BOTAŞ (18%) and TPAO (1%). Construction of new refineries will add 18.9 mb (3 mcm) of storage capacity, while the Samsun-Ceyhan oil pipeline project plans to construct 14 oil tanks amounting to 13.2 mb (2.1 mcm). With the completion of these two new infrastructure projects, the total storage capacity of the country will be expanded to over 110 mb (17.5 mcm).

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Decision-making structure

The National Oil Stock Commission (NOSC) is responsible for energy security in the event of supply disruption. The commission is chaired by the Undersecretary of the Ministry of Energy and Natural Resources (MENR) and is composed of the Undersecretary of the Treasury and representatives from the Ministry of National Defence, the Ministry of Foreign Affairs, the Ministry of Finance, the Ministry of Interior Affairs, the Energy Market Regulatory Authority (EMRA), and the General Directorate of Petroleum Affairs (GDPA). The MENR and the GDPA serve as the secretariat and form the core of the Turkish national emergency strategy organisation (NESO). The Petroleum Market Law provides the legal basis for establishing the NESO.

During an emergency, the chairman of the NOSC will convene a meeting with the commission members to make a decision to release compulsory industry stocks, which is estimated to be taken within two days. Decisions of the NOSC will be implemented by the GDPA in close co-operation with the industry.

Stocks

Stockholding structure

Turkey meets its stockholding obligation to the IEA by placing a minimum stockholding obligation on industry. According to the Petroleum Market Law, the country should hold oil stocks equivalent to at least 90 days of its net imports.

Refineries and fuel distribution licensees are obliged to hold at least 20 days of product stocks based on the average daily sales of the previous year. These stocks must be held at their own storage or licensed storage facilities. New entrants into the distribution market are obliged to hold a minimum of 3.3 kilotonnes of stock. Eligible consumers who use more than 20 Kt on an annual basis are also obliged to hold 15 days' consumption of each type of liquid fuel in their consumption inventory. In addition, refineries are asked to hold, on behalf of the government, complementary stocks which correspond to the remaining balance of 90 days of net oil imports. However, the complementary stocks are not yet in place, although refineries usually hold a quantity of commercial oil stocks beyond the amount requested as complementary stocks. The draft Law on Complementary Oil Stocks is expected to ensure that the complementary stocks are held in an appropriate manner.

Crude or products

At the end of April 2013, Turkey held some 63 mb of oil stocks, equal to 93 days of 2012 net imports. Around 56% of total oil stocks are held in the form of crude oil, as refineries are permitted to hold crude oils in place of gasoline and diesel on the condition that they report the amount and the type of substitution. Middle distillates account for 21% of the country's total stocks, followed by motor gasoline (5%).

Location and availability

Since Turkish legislation does not allow emergency oil reserves to be held abroad, Turkey has no bilateral agreements or ticket arrangements with other countries. All emergency oil stocks are held in the country.

Although compulsory stocks are commingled with commercial and operational stocks in storage, emergency oil stocks are considered to be held on top of the minimum operating requirements (MOR) of the industry.

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Monitoring and non-compliance

The EMRA conducts regular on-site audits of randomly selected facilities twice a year to monitor the physical availability and quality of compulsory stocks. These audits are carried out in co-operation with the Ministry of Science, Industry and Technology. Technical requirements are also tested on site by individual experts.

In cases of failure to comply with stock obligations in terms of quality, quantity and location of oil products, companies can be be obliged to pay fines, and, in case of serious infringement, the licence of the company may be cancelled.

Stock drawdown and timeframe

The Petroleum Market Law requires a decision by the NOSC to draw down compulsory industry stocks during an oil supply disruption. Based on the decision taken by the NOSC, the GDPA will request industry, according to their obligation, to release the necessary oil stocks in close co-operation with the EMRA. Stock release will most likely be made by refineries. The government's decision could be made in two days and release of stock is estimated at three days.

Financing and fees

The government does not provide financial support for building compulsory industry stocks. All refineries, distributors and eligible consumers must self-fund the operational costs of meeting their emergency requirements. These costs are implicitly passed on to final consumers in market prices.

Other measures

Demand restraint

Demand restraint is considered a secondary emergency response measure that could complement an oil stock release in Turkey.

Turkey's demand restraint measures would range from light-handed measures (e.g. information and energy saving campaigns) on a recommendation basis, to heavy-handed measures (e.g. mandatory speed limits, a ban on weekend driving and short distance driving, temporary restrictions on heating for houses and public buildings under 15 °C, restriction on the lighting of shop windows, prohibition of motor sports, introduction of delivery quotas of gasoline, tax increases and rationing) which would be deployed only in case light-handed measure are not enough to reduce oil consumption.

The decision to implement demand restraint measures will be taken by the Co-ordination Board, established under the Law on Organisation and Duties of Headship of Disaster and Emergency Management in 2009. The Co-ordination Board will be advised by the NOSC. Approval by parliament is required for implementation of tax increase and rationing/allocation measures. Local governors are asked to implement demand restraint measures which the Co-ordination Board decides according to the severity of the crisis.

Fuel switching

Short-term fuel switching from oil to other fuels is not regarded as an emergency response measure in Turkey, as the share of oil in the power generation sector was estimated to be only some 1% in 2012. There is little potential to switch away from oil to other energy sources in this sector.

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Other

According to the Petroleum Law, the administration can ask producing companies to increase oil production. Domestic production surge is estimated to be a 5% to 10% increase of production for 10 days in time of crisis. However, it is too little to cover domestic oil demand since the country's annual crude oil production was around 45 kb/d in 2012.

Gas

Market features and key issues

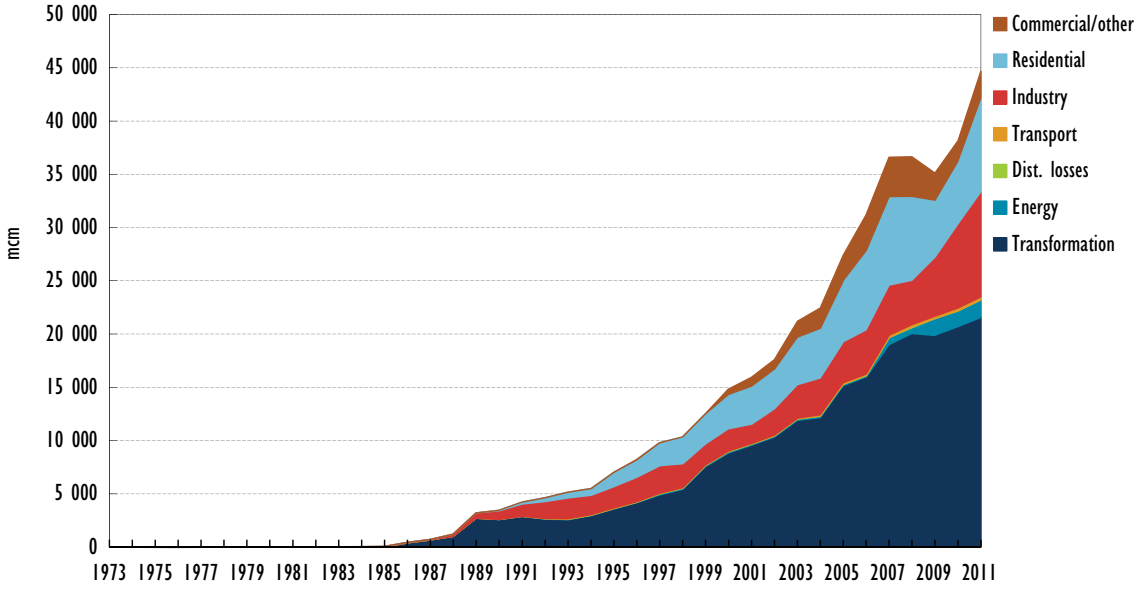
Gas production and reserves

In 2012, indigenous natural gas production totalled some 0.63 bcm. Gas production is projected to be depleted.

Gas demand

Turkey's demand for natural gas significantly increased in 2012 from some 0.7 bcm (2 mcm/d) in 1987 to around 45 bcm (124 mcm/d).

Figure 4.27.6 Natural gas consumption by sector, 1973-2011



In 2011, the transformation sector was the largest consumer of natural gas, representing about 48% of Turkey's total gas consumption, while the industry and the residential sector represented 22% and 20% respectively. The Turkish monthly peak gas demand stood at some 5.2 bcm in January 2012. Daily peak demand was recorded in the same month, amounting to around 186 mcm/d.

Given that electricity demand is estimated to increase by 7.5% annually until 2020, gas demand may rise at a significant rate despite efforts to promote non-fossil fuels for electricity generation. In 2012, natural gas accounted for some 44% of total electricity generation.

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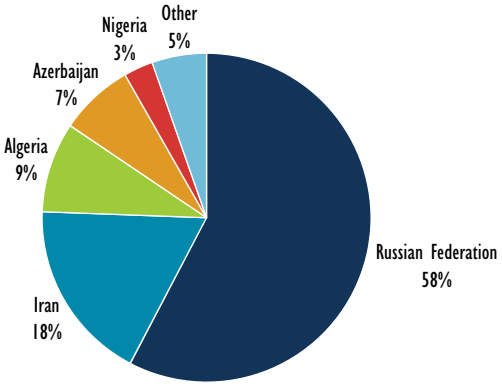
Gas import dependency

Because of its limited indigenous natural gas production, Turkish gas demand is mostly supplied by imports through pipelines or in the form of LNG. The country's total natural gas imports in 2012 amounted to some 46 bcm (125.8 mcm/d).

Figure 4.27.7 Natural gas imports by source, 2012



In 2012, Russia was Turkey's largest supplier, representing 58% of total imports, followed by Iran (18%), Algeria (9%) and Azerbaijan (7%). Most natural gas is carried through international pipelines from Russia, Iran and Azerbaijan. Natural gas from Algeria and Nigeria is imported in the form of LNG. Turkey's natural gas imports are dependent on long-term contracts.

Gas company operations

The gas market was liberalised in May 2001, with the Natural Gas Market Law N° 4646 which obliges state-owned BOTAŞ to reduce its market share in imports, wholesale and distribution. However, BOTAŞ still remains a dominant gas market player. Some 39 bcm of natural gas were imported by BOTAŞ in 2011, while about 5 to 6 bcm were imported by private gas importers. In 2012, the amount of gas imported by BOTAŞ was 43.1 bcm.

At the end of 2011, there were some 9.1 million contracts when residential gas consumption reached 11.3 bcm.

Gas supply infrastructure

Ports and pipelines

The transmission division of BOTAŞ is Turkey's national TSO. The transmission system has approximately 9 555 km of pipeline within Turkey. With the inclusion of the distribution grid, the total length of the gas grid is around 12 290 km. The country has nine entry points: four points through international pipelines, two LNG terminals, two domestic production areas and one storage facility.

The system comprises seven gas compressor stations with a total compressor capacity of 250 MW and over 200 pressure-reducing and metering stations. As the country faces difficulty in transferring imported gas from east to northwest with its current compression capacity, two new compressor stations with a capacity of 98 MW are expected to be integrated into the transmission system. Turkey has 290 primary exit points: 53 points are operated by the BOTAŞ transmission division, while 237 entry points are operated by distribution companies.

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There are four international gas pipelines in operation with a total import capacity of some 46.6 bcm (around 127.6 mcm/d or 5.3 mcm/h): the Russia-Turkey West Gas Pipeline with a capacity of 16 bcm via Kofcaz on the border with Bulgaria; the Russia-Turkey Blue Stream Natural Gas Pipeline with a capacity of 14 bcm via Samsun on the Black Sea; the Iran-Turkey Pipeline with a 10 bcm capacity via Dogubayazi close to the border with Iran; and the Baku-Tbilisi-Erzurum Pipeline with a capacity of 6.6 bcm through Georgia via Ardahan. The country also exports natural gas to Greece through a pipeline with a maximum capacity of 2.4 mcm/d.

Turkey is engaged in the Trans-Anatolian Natural Gas Pipeline (TANAP) project to transport natural gas from the Shah Deniz field in Azerbaijan to Europe through Turkey with a capacity of 16 bcm; 6 bcm of this amount is expected to be imported for Turkish domestic gas use with the remaining 10 bcm destined for Europe.

As an important transit country, Turkey also participates in other international pipeline projects: the Arab National Gas Pipeline will bring Egyptian gas to Turkey and Europe through Jordan, Lebanon and Syria; Turkmenistan-Turkey-Europe Natural Gas Pipeline will transport 30 bcm of Turkmen gas to Turkey (16 bcm) and Europe (14 bcm); and the Iraq-Turkey Natural Gas Pipeline project is planned for construction in parallel with the existing Kirkuk-Ceyhan Crude Oil Pipeline.

Turkey has two LNG regasification terminals with a total maximum annual capacity of around 14 bcm. BOTAŞ owns the Marmara Ereglisi LNG Terminal which has a maximum send-out capacity of some 22 mcm/d. Ege Gaz operates the Aliaga Terminal with a capacity of 16.4 mcm/d. A construction project for a new LNG terminal, which is expected to have a capacity of 18 mcm/d, is under evaluation.

Storage

Turkey has around 3 bcm of storage capacity in total, with a sending-out capacity of some 58.5 mcm/d. As this is not sufficient to meet its increasing gas demand, in 2008 the Strategic Plan of the MENR set a target to increase gas storage capacity to 4 bcm by the end of 2014.

In 2012, Turkey had 2.66 bcm of underground storage at two depleted gas fields close to Istanbul for seasonal balancing, peak shaving and gas supply shortage. TPAO operates those storage facilities with an injection capacity of 16 mcm/d and a withdrawal capacity of 20 mcm/d in total. The storage capacity of the facility is expected to be expanded to reach 2.84 bcm with a withdrawal capacity of 25 mcm/d in the second phase of construction by the end of 2014, and then 4.3 bcm with a withdrawal capacity of 70 mcm/d in the revised phase III by 2017.

Several projects are ongoing: one is the Tuz Gölü (salt lake) natural gas storage project in the Central Anatolia region. The first phase, which includes the construction of six domes is planned for completion in 2015-16; the second phase in 2018-19 will increase the facility by an additional six units.

BOTAŞ also operates three LNG storage tanks with a total capacity of 255 000 m^3 of LNG or 156.8 mcm of natural gas in Marmara Ereglisi; Ege Gaz owns 280 000 m^3 of LNG storage (or 172.2 mcm of natural gas) in Aliaga.

Emergency policy

Key elements of Turkey's overall gas security policy are diversifying its long-term supply contract portfolio, forming an energy hub from Central Europe and the Middle East to Europe, increasing its natural gas storage facilities, cutting back contractual supplies and installing voluntary fuel switching to alternative fuels in power generation.

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The Natural Gas Market Law N° 4646 (2001) sets the standard of gas supply security for suppliers. Gas importers (except spot LNG importers) are obliged to hold gas in storage to a capacity corresponding to 10% of their annual gas imports, although they are not necessarily asked to hold such an amount of natural gas in storage. In light of the law, the Transmission Network Operation Principles (network code) was approved by the EMRA to regulate the operation of the TSO and the companies involved, such as distributors and importers in the event of a natural gas shortage. According to the code, BOTAŞ transmission division would take the lead in the event of a supply disruption under the supervision of the EMRA.

In 2011, the Minister of Energy and Natural Resources approved an action plan on additional contingency measures. Under the action plan, the Commission for Enduring and Supervising Security of Natural Gas Supply, CESS-NGS, was established with the participation of the Undersecretary of the MENR (chairperson), the EMRA, the General Directorate of Energy Affairs of the MENR, the Turkish Electricity Transmission Corporation (TEİASŞ), the state-owned Electricity Generation Company (EÜAŞ), the Turkish Electricity Trading and Contracting Company (TETAŞ) and BOTAŞ. The CESS-NGS plans to amend the National Gas Market Law in order to oblige all power plants with fuel-switching capacity to hold sufficient amounts of secondary fuel such as diesel. It is also planned that all periodic maintenance is to be kept at minimum levels during the winter months.

Emergency response measures

Using an electronic bulletin board, the TSO announces "difficult days" when heavy imbalances in the system occur, caused by excessive withdrawals or insufficient gas entries. Suppliers are requested to implement disruption and interruption orders from the TSO within 8 hours.

When the gas importers concerned can be identified, gas supplies can be curtailed in accordance with the end-user priority list which is submitted by gas importers every year.

In case of gas supply disruption in which the gas suppliers responsible are not identified, the TSO will first endeavour to curb gas consumption by implementing interruptible contracts. However, the share of such contracts with BOTAŞ is limited to around 1.4% of its total sales, because prices between normal contracts and interruptible ones make no significant difference.

The TSO will also reduce the contractual capacities of gas-fired power plants which can switch to alternative fuels, and then cut gas supplies to other power plants. The total amount of dual-fired power generation was around 3.5 GW (or some 8.4 mcm/d at net caloric value), with most generating electricity for their own facilities.

When the above measures are not considered sufficient to mitigate the impact of a gas disruption, the TSO will reduce gas supplies to industry and eventually to households.

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United Kingdom

Key data

Table 4.28.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	1 939.9	2 694.4	1 838.2	1 360.6	1 114.8	950.8	1 003.8
Demand (kb/d)	1 775.9	1 765.4	1 819.5	1 621.5	1 583.8	1 502.7	1 442.7
Motor gasoline	562.8	498.8	435.2	349.5	333.6	319.7	-
Gas/diesel oil	414.4	511.5	557.3	568.8	567.5	574.7	-
Residual fuel oil	269.7	80.7	89.3	66.0	63.8	47.7	-
Others	529.0	674.6	737.7	637.1	618.9	560.5	-
Net imports (kb/d)	- 164.0	- 929.0	- 18.7	260.9	469.0	551.9	438.9
Import dependency (%)	- 9.2	- 52.6	- 1.0	16.1	29.6	36.7	30
Refining capacity (kb/d)	1 831.0	1 784.7	1 825.4	1 925.0	1 925.0	1 925.0	-
Oil in TPES (%)**	37	33	33	31	32	31	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.28.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	49 672	115 386	92 805	59 776	47 670	41 054	35 606
Demand (mcm/y)	58 312	101 812	99 643	98 944	82 428	78 083	78 277
Transformation	1 374	31 641	32 048	35 972	30 098	0	-
Industry	14 754	17 831	14 418	11 744	12 051	0	-
Residential	28 677	33 451	34 275	35 252	26 638	0	-
Others	13 507	18 889	18 902	15 976	13 641	0	-
Net imports (mcm/y)	8 640	- 13 574	6 838	39 168	34 758	37 029	42 672
Import dependency (%)	14.8	- 13.3	6.9	39.6	42.2	47.4	55
Natural gas in TPES (%)	23	39	39	42	37	34	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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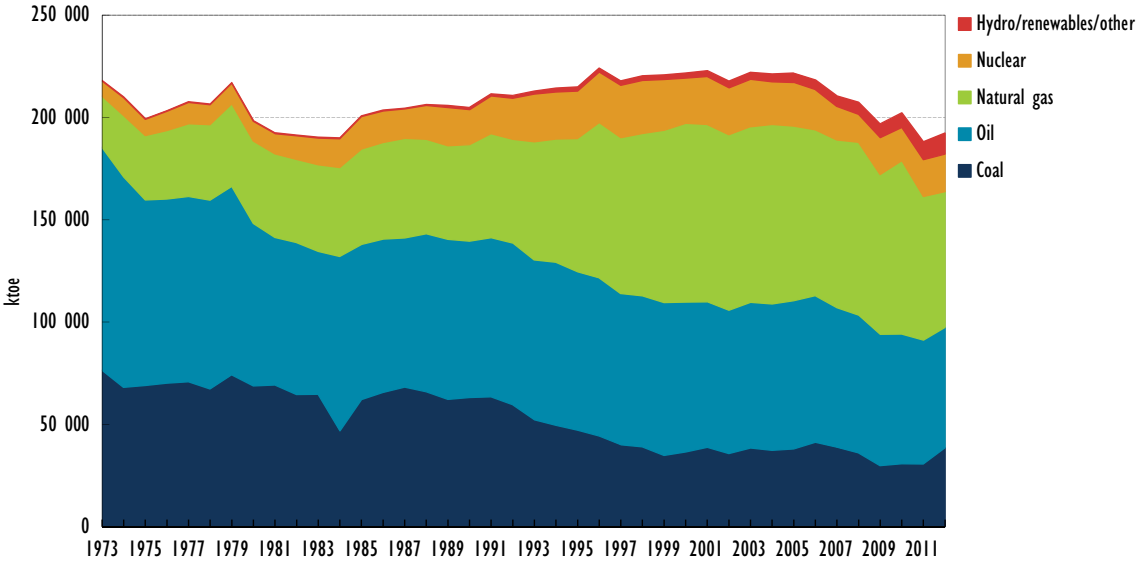
Figure 4.28.1 Total primary energy source (TPES) trend, 1973-2012



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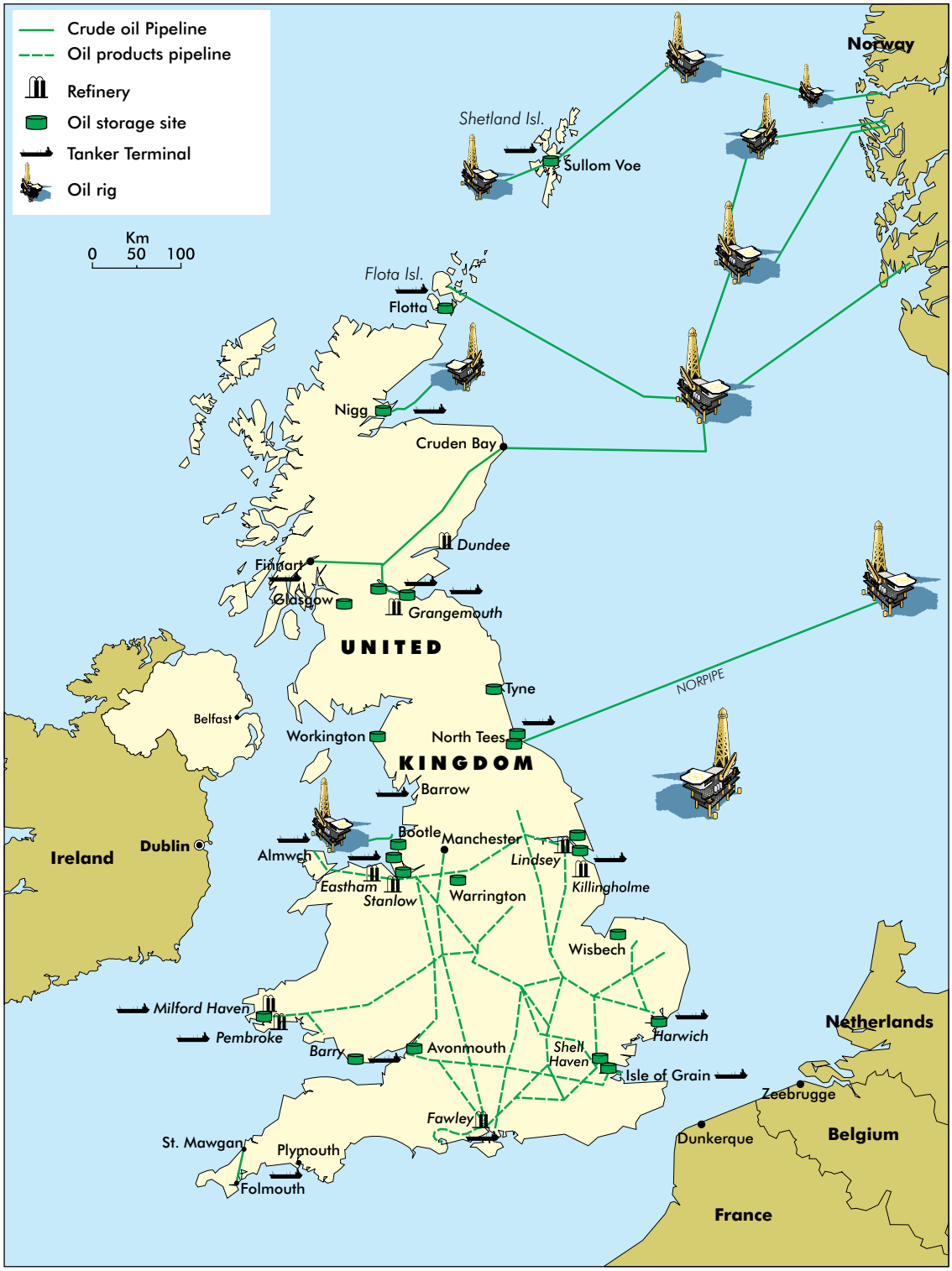
Map 4.28.1 Oil infrastructure of the United Kingdom



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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Map 4.28.2 Gas infrastructure of the United Kingdom

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

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Country overview

Oil has been one of the dominant – although declining – energy sources in the United Kingdom, accounting for 32% of the country's total primary energy supply (TPES) in 2012. The United Kingdom has significant levels of domestic crude oil production, although production has declined, on average, by 7% per year since peaking at 2.9 million barrels per day (mb/d) in 1999. The country became a net importer of oil in 2005.

Total UK oil demand has also gradually declined since 2005. In 2012 average demand was 1.5 mb/d, down from 1.8 mb/d in 2005. The transport sector accounted for 71% of total oil consumption in 2011 – up from 66% in 2000. UK oil imports averaged 504 kb/d in 2012, accounting for 37% of the country's oil demand in 2012. The United Kingdom has relatively diversified crude import sources, with 46% of imports in 2012 coming from Norway, followed by Nigeria with 13% and the Russian Federation with 12%.

The Department of Energy and Climate Change (DECC) is responsible for co-ordinating the country's response to oil supply emergencies. The United Kingdom meets its International Energy Agency (IEA) stockholding obligation through a compulsory stockholding obligation (CSO) on oil companies. Refining companies are required to hold stocks equivalent to 67.5 days of their supplies during the previous four quarters, while importing companies must hold stocks equivalent to 58 days. There are no public stocks and the country does not have a public stockholding agency.

The UK held about 83 mb of oil and product stocks at the end of July 2013, equal to 224 days of 2012 net imports. Around 40% to total stocks were held in the form of crude and 60% as finished product.

Natural gas as a proportion of TPES has been in decline in the United Kingdom in recent years, dropping to 34% of TPES in 2012 from 42% in 2010. In 2012 total natural gas production was 41 bcm, considerably less than half of the level in 2000. Gas demand was 78 bcm in 2012, down from 82 bcm in 2011 and 98 bcm in 2010. In 2011, the transformation and residential sectors each accounted for about 36% of total gas consumption. Natural gas is the largest single source of fuel for electricity generation in the country, accounting for 40% of total power generation inputs in 2011.

UK natural gas imports amounted to 37 bcm in 2012 – around 47% of its requirements. The country's imports are relatively diversified, with significant imports from Norway (54% of total imports), Qatar (26%) and the Netherlands (15%). It has also expanded and diversified its gas import infrastructure to compensate for the ongoing decline in domestic production.

Three pipelines with a combined capacity of 47 bcm link the UK gas network to Norway, and two other pipelines with a combined capacity of 46.5 bcm link the United Kingdom to Europe via Belgium and the Netherlands. The United Kingdom also has four liquefied natural gas (LNG) import terminals with a combined capacity of 30.4 bcm.

The working natural gas storage capacity of the United Kingdom is approximately 4.7 bcm. The maximum daily delivery from storage is 135 million cubic metres per day (mcm/d). This is around a quarter of the peak-demand estimate of the National Grid (511 mcm/d for winter 2013/14) and 29% of the highest actual demand (465 mcm/d) recorded in January 2010. On average, gas storage makes up about 10% of the overall gas supply mix over the winter period.

UK natural gas security of supply relies primarily on diversification of import sources and infrastructure and supply routes, backed up by substantial gas storage facilities.

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Oil

Market features and key issues

Domestic oil production

The United Kingdom has significant levels of domestic crude oil production and ranks fourth among the IEA countries, after the United States, Canada and Norway. However, UK oil production has declined on average by 7% per year since peaking at 2.9 mb/d in 1999; the country became a net importer of oil in late 2005.

In 2012 domestic UK oil production averaged 951 kb/d – down from 1.36 mb/d in 2010 and 1.84 mb/d in 2005. According to government figures, production is expected to continue to decline for the foreseeable future – falling below 800 kb/d around 2020. IEA forecasts are slightly more optimistic, with domestic production expected to rebound to around 1 mb/d in 2018.

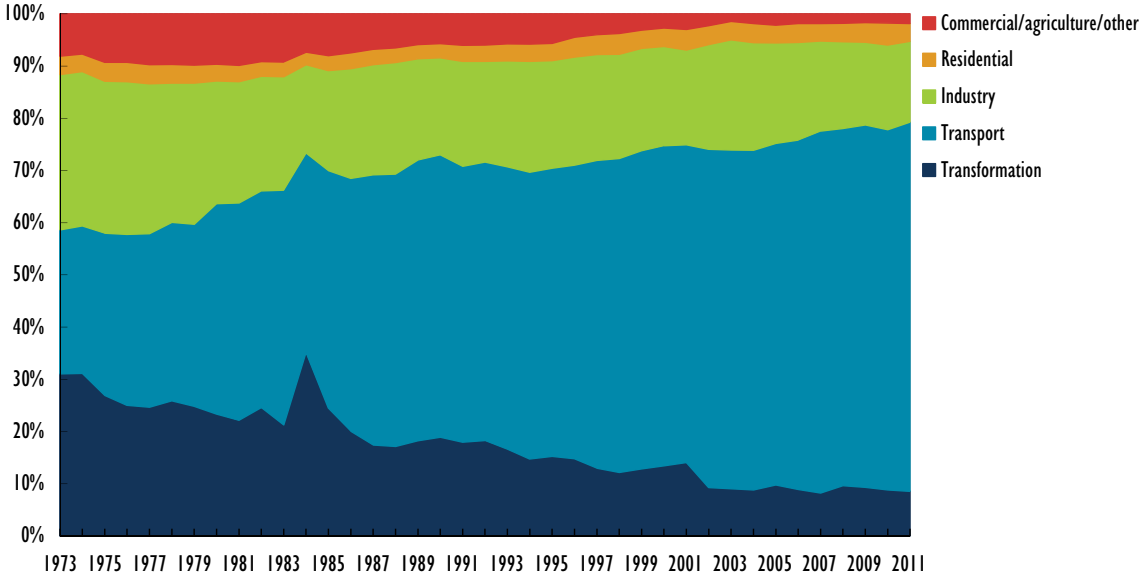
Almost all UK oil is produced from offshore fields, mainly in the North Sea.

Oil demand

Total UK oil demand has gradually declined since 2005. Oil demand in 2012 averaged 1.5 mb/d, down from 1.6 mb/d in 2010 and 1.8 mb/d in 2005. The downward trend is expected to continue, and is forecast to reach 1.4 mb/d by 2018; this is largely because of a declining demand for gasoline.

Oil accounted for 32% of the country's TPES in 2012. The largest area of oil consumption in the United Kingdom is the transport sector, which accounted for 71% of total oil consumption in 2011 – up from 66% in 2000 and 58% in 1990. Industry was a distant second at 15%.

Figure 4.28.2 Oil consumption by sector, 1973-2011



Reflecting the dominance of the transport sector in UK oil consumption, the main oil products used are diesel, gasoline and jet fuel and kerosene. Diesel alone accounted for

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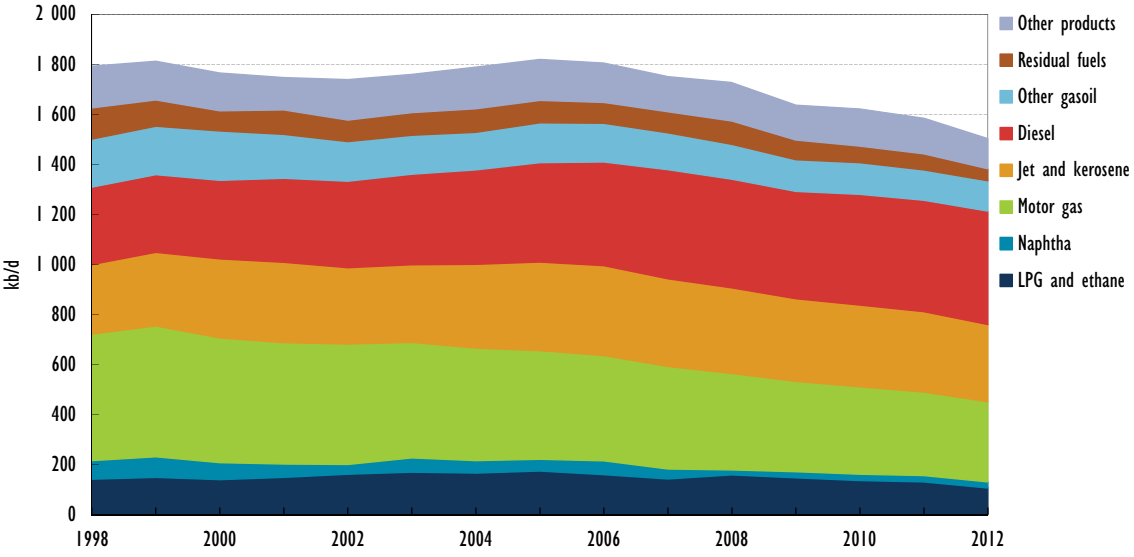
30% of total oil demand in 2012, followed by motor gasoline at 21% and jet fuel and kerosene also at 21%.

Figure 4.28.3 Oil demand by product, 1998-2012

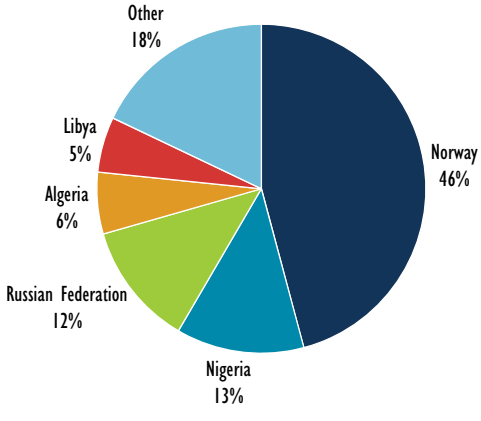


Imports/exports and import dependency

In 2012 net UK crude oil imports averaged 504 kb/d. The United Kingdom has been a net importer of oil since 2006, with imports accounting for 37% of the country's oil demand in 2012 – up from 30% in 2011 and 16% in 2000.

UK crude import sources are relatively widely diversified, with 46% of imports in 2012 coming from Norway, followed by Nigeria with 13% and Russia with 12%.

Figure 4.28.4 Crude oil imports by origin, 2012



The United Kingdom is also a significant producer of refined product, with refining capacity of 1.9 kb/d, and is a net product exporter – albeit in limited quantities (29 kb/d in 2012 and 89 kb/d in 2011).

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Oil company operations

There are more than 200 companies involved in the distribution and marketing of oil products in the United Kingdom – ranging from oil companies, supermarkets and retail chains to small, independent retailers.

The retail market covers fuels mainly sold from the country's 8 600 filling stations (as of the end of 2012). The number of filling stations has more than halved since 1990. The major suppliers (BP, Esso, Texaco and Shell) have over 4 000 branded stations though many of these are operated by independent dealers. The market is a complex one with over 2 000 sites operated and owned by companies and a further 5 000 operated by independent dealers. At the end of 2012, the four largest supermarkets owned over 13 000 stations and supplied over 40% of the retail fuel market.

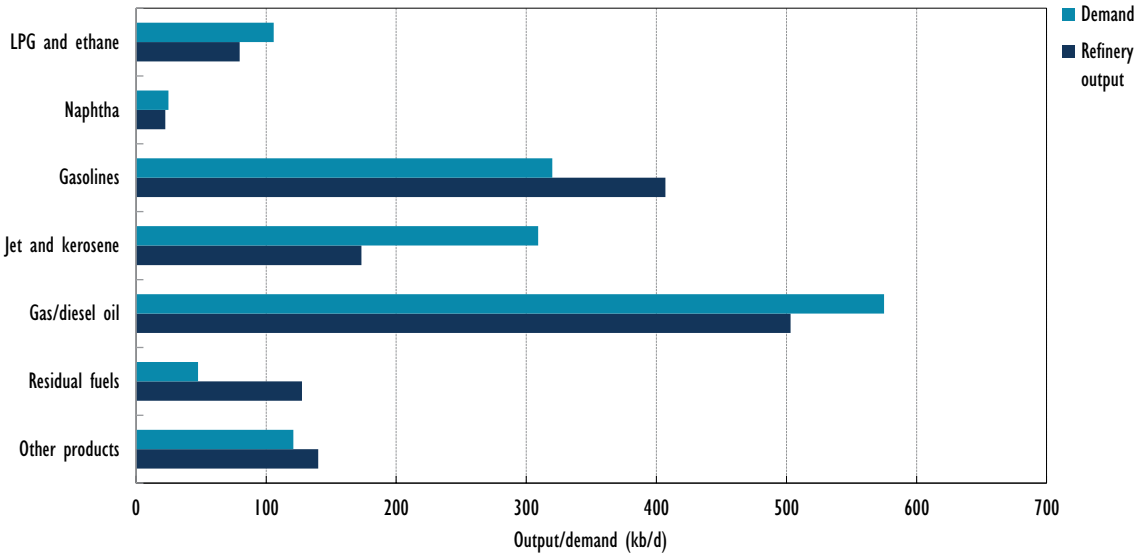
Oil supply infrastructure

Refining

There are seven major refineries operating in the United Kingdom, with a combined output of around 1.5 mb/d in 2012. Together, these refineries supply over 90% of the inland market demand for oil products. The country also has three smaller petrochemical refineries producing specialty products such as solvents, process oils and bitumen.

The UK refining sector, in common with other European countries, faces a number of challenges, including weak refining margins, increasing global refining capacity and overcapacity, increasing environmental and regulatory burdens and an increasing supply/demand imbalance of refined products. With regard to this imbalance, the United Kingdom imported a net 189 kb/d of middle distillates in 2012, and exported 85 kb/d of motor gasoline.

Figure 4.28.5 Refinery output vs. demand, 2012



Vertically integrated international oil companies (IOCs) have traditionally dominated the refining sector. However, in response to challenging conditions in European countries and to opportunities elsewhere, the IOCs have reduced their presence in the domestic refining business. For example, BP withdrew from the domestic refining sector after the sale of its Grangemouth and Coryton refineries in 2007. Shell also exited in 2007

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after selling its Stanlow refinery to Essar Energy, and Chevron Texaco sold its Pembroke refinery and related assets to Valero Energy Corporation that same year. In January 2011, Ineos announced a joint venture agreement with Petrochina for the Grangemouth refinery and its related assets. Finally, and most significantly, the Coryton Refinery closed in June 2012 following the bankruptcy of Petroplus.

Ports and pipelines

The United Kingdom has a 4 800 km oil pipeline network – including the pipelines connecting onshore oil terminals to the North Sea oil fields. Around half of the pipeline network is privately owned and the other half is government owned.

The privately owned sections of the domestic pipeline network carry a variety of oil products around the country – from road transport fuels to heating oil and aviation fuel. This includes the provision of jet fuel for some of the major airports, including Heathrow, Gatwick, Manchester and Birmingham. The government operates a separate oil pipeline system – the Government Pipeline and Storage System (GPSS) – supplying a number of military airfields and with connections to some commercial airports, such as Stansted and Manchester.

The United Kingdom also has four major land-based terminals through which about two-thirds of the country's crude oil production flows. They are Sullom Voe (Shetlands), Flotta (Orkneys), Kinneil (at the end of the Forties Pipeline System) and Teeside on the east coast. Hamble, another mainland terminal, deals with oil coming from several onshore oilfields in the south of England. These terminals supply more than one-third of total crude to UK refineries.

Storage capacity

A total of 83 mb of oil and product stocks were held on UK territory as of July 2013. The main storage facilities for crude and oil products in the United Kingdom are located at refineries. A number of major product distribution terminals also serve as self-contained, separate storage and distribution facilities. Altogether, the refinery and stand-alone terminals comprise a total of 59 primary distribution terminals. They are collectively supplied by pipeline (51% by volume), rail (15%), and sea (34%) from UK refineries and – in some cases – from overseas.

Decision-making structure

The DECC is responsible for co-ordinating the country's response to oil supply emergencies. Within the department, the Energy Resilience Team (ERT) serves as the national emergency strategy organisation (NESO). This team is responsible for maintaining and implementing emergency response measures in an oil supply disruption, and also for supervising the guidelines that companies are required to follow with regard to security of natural gas supplies.

The legal basis for DECC's authority to function as the NESO during an oil supply disruption is the Energy Act 1976. The act provides powers, subject to an order in council, for the Secretary of State for Energy and Climate Change to regulate or prohibit the production, supply, acquisition or use of fuel in a domestic oil supply emergency, or in order to enable the United Kingdom to meet its international obligations in the event of an IEA collective action.

In the event of an emergency – once the NESO has been activated – the UK government has two primary emergency response policy options: 1) draw down oil stocks by lowering the CSO on industry; and 2) instigate demand restraint measures.

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The government's preferred option for responding to an emergency is to draw down oil stocks – and there is a six-stage process in place to activate this option. During the IEA collective action in 2005 following Hurricane Katrina and again in 2011 during the Libyan crisis, the United Kingdom met its IEA obligations by reducing the CSO on industry and drawing down oil stocks.

Stocks

Stockholding structure

The United Kingdom meets its IEA stockholding obligation through a CSO on oil companies. There are no public stocks, and the country does not have a public stockholding agency.

Section 6 of the Energy Act 1976 allows the Secretary of State for Energy and Climate Change to direct companies that produce, supply or use petroleum products within the UK market to hold minimum levels of oil stocks (and to release them to the market in an emergency). Accordingly, refining companies must hold stocks equivalent to 67.5 days of their supplies during the previous four quarters, while importing companies must hold stocks equivalent to 58 days. Other stocks, predominantly those held off shore, also contribute towards the UK total.

As the country's oil production is decreasing, net imports are set to rise significantly in the short to medium term and, consequently, its stockholding obligations to the IEA and the EU are expected to rise progressively. Under the EU Directive of 14 September 2009 on crude oil and petroleum product stockholding obligations (Council Directive 2009/119/EC), the United Kingdom is obliged to hold "90 days of average daily net imports or 61 days of average daily inland consumption, whichever of the two quantities is greater". The country's 90-day IEA/EU obligation is not expected to overtake the consumption-based EU obligation until the early to mid-2020s. Once this takes place and the United Kingdom switches to calculating its minimum stockholding requirements on the basis of the IEA/EU 90-day obligation, the country will need to hold progressively more stocks than it has previously as the proportion of imports continues to grow.

Crude or products

Approximately 40% of the stocks held in the UK are in the form of crude oil.

Location and availability

There are no restrictions on the location of compulsory stocks in the United Kingdom. However, companies must report, on a monthly basis, the location of all stocks that count towards their obligation. Compulsory stocks are often commingled with company operating stocks.

Compulsory stocks can be held in three ways: by the company itself in the United Kingdom, by third parties, on behalf of the company within the United Kingdom, or by the company, by an affiliate or by third parties in another EU member state, provided that the affected stocks are held under a bilateral agreement between the United Kingdom and the relevant member state.

Monitoring and non-compliance

Oil companies and importers are required to submit monthly oil returns to the DECC. A compliance report detailing any inconsistencies in the data is forwarded to each

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company monthly. All stock data, and physical stocks, are subject to audit if required. In cases where a company fails to comply with its obligations, the DECC is empowered under Schedule 2 of the Energy Act 1976 to investigate and, if necessary, to prosecute.

Stock drawdown and timeframe

During the implementation stage of a stockdraw, companies are obliged to develop an implementation plan and notify the DECC. Stocks would be expected to be drawn down within an agreed timeframe – usually one month. The DECC's preference is for implementation plans to be made on a voluntary basis, but in the event that acceptable company-specific implementation plans cannot be agreed on, the DECC would use its legal authority to direct companies to release stock.

Financing and fees

The costs of compulsory oil stocks are financed by the companies operating in the market, and thus implicitly passed on to consumers through market prices.

Other measures

Demand restraint

The transport sector accounts for the majority of UK oil consumption – representing 71% of total consumption in 2011. Therefore, the most effective demand restraint measures – and consequently the most likely to be used in an emergency – would be targeted towards the use of transport fuels.

Under the Energy Act 1976, the UK government has the authority to control the production, supply, acquisition and use of oil and oil products as it deems necessary. In principle, the government prefers to allow market mechanisms to resolve temporary disruptions to the greatest extent possible. In a disruption requiring government action, light-handed measures are preferred; more heavy-handed demand restraint and allocation measures would be unlikely. However, should a serious crisis emerge, these could be introduced as necessary.

Demand restraint measures in the United Kingdom are set out in the National Emergency Plan for Fuel (NEP-F). A number of measures can be considered as part of an emergency response to any situation involving fuel supply disruption, ranging from light-handed measures to the allocation and rationing of oil products.

Fuel switching

This is not a viable option at present. Oil-fired electricity generation in the United Kingdom is minimal (less than 1% in 2013), so the scope for fuel switching is limited. However, around 15 combined-cycle gas turbine (CCGT) power stations have stocks of middle distillate to provide backup generation sufficient to keep functioning for up to seven days in the absence of natural gas supplies.

Other

The UK government is unlikely to consider surge production as an emergency response measure as this could damage oil fields and reduce their long-term viability. However, the government does have the power to require this measure under the Energy Act 1976.

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Gas

Market features and key issues

Gas production and reserves

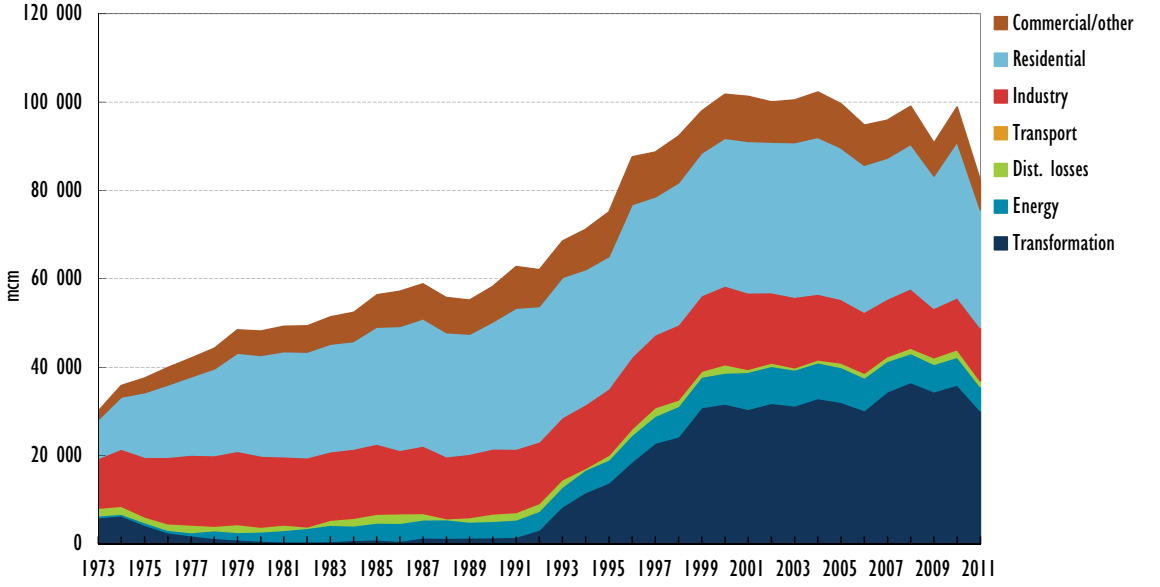
UK natural gas production comes primarily (99.9%) from offshore fields – mostly from the North Sea but also from the Irish Sea. Production peaked in 2000 at 115 bcm, and has declined quickly since then at a rate of about 6% per year. In 2012, total gas production was 41 bcm – less than half of the level in 2000. The decline is expected to continue and gas production is expected to drop to just over 35.5 bcm by 2018.

Gas demand

Natural gas demand in the United Kingdom was 78 bcm in 2012, down from 82 bcm in 2011 and 98 bcm in 2010. Natural gas as a proportion of TPES has also been in decline in recent years, dropping to 34% of TPES in 2012, from 37% in 2011 and 42% in 2010. The decline in natural gas demand is expected to plateau in the short to medium term, with demand rising slightly to 78.3 bcm by 2018.

UK natural gas demand peaks during the winter months. The record peak natural gas demand experienced on the UK gas network was 465 mcm/d in January 2010.

Figure 4.28.6 Natural gas consumption by sector, 1973-2011



The biggest areas of natural gas consumption in the United Kingdom are the transformation and residential sectors, each accounting for a 36% share of total demand. Natural gas is the largest single source of fuel for electricity generation in the country, accounting for 40% of total power generation inputs in 2011.

Gas import dependency

The United Kingdom has been a net importer of gas since 2004, and in 2012 the country imported fully 47% of its requirements from overseas. This figure is up sharply from 42%

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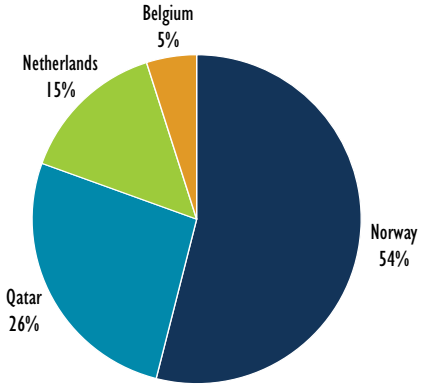
in 2011, 40% in 2010, and 7% in 2005. This trend is expected to continue, with natural gas imports forecast to meet 55% of total demand in 2018.

Figure 4.28.7 Natural gas imports by source, 2011



Gas company operations

The UK natural gas sector is privately controlled, including production, distribution and transmission. The largest gas supplier in the United Kingdom is Centrica, a spin-off of the assets of formerly state-owned British Gas. The National Gas Grid (NGG) controls the domestic gas transmission system.

Gas supply infrastructure

Ports and Pipelines

The United Kingdom has a natural gas pipeline distribution network that is around 285 000 km in length and provides services to almost 23 million users. In addition, the country has a 7 600 km high-pressure transmission pipeline network which transports gas from import points (pipeline or LNG terminals) to major centres of population as well as to some large users, such as gas-fired power plants. These pipeline networks comprise the National Transmission System (NTS), which is owned and operated by NGG.

In order to compensate for the decline in production, the United Kingdom has expanded and diversified its gas import infrastructure. Three pipelines with a combined capacity of 47 bcm link the country's gas network to Norway (incoming flows from North Sea fields). Two other pipelines link the United Kingdom to continental Europe. The first is the Interconnector UK, a two-way pipeline with a capacity to import up to 26.9 bcm to the United Kingdom, or export up to 20 bcm to Belgium. This pipeline is generally used for imports in winter and exports in summer. The other pipeline connecting the United Kingdom to continental Europe is the Balgzand to Bacton (BBL) pipeline. The BBL is a one-way pipeline with a capacity of 19.5 bcm used to import gas into the United Kingdom from the Netherlands.

The United Kigndom also has four LNG import terminals, namely Teesside GasPort (capacity 4 bcm), Isle of Grain (capacity 20.4 bcm), South Hook Milford Haven (21 bcm) and Dragon LNG (6 bcm). There are no UK import projects under construction; however there are six proposed projects with the potential to increase LNG capacity and diversity of supply.

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Storage

The working natural gas storage capacity of the United Kingdom is approximately 4.7 bcm. Historically, it has had less need of gas storage capacity than other major gas markets within the European Union because of "swing production capacity" provided by indigenous gas fields. As these fields continue to decline there is an increasing need for replacement "swing supply capacity" – including from additional import infrastructure and gas storage capacity.

The country has three types of gas storage: long-range storage, medium-range storage (typically salt caverns such as Aldbrough, and depleted fields such as Hatfield Moor), and short-range storage (peak LNG plants). Long-range storage is typically used for seasonal variations. Rough, the only such facility in the United Kingdom, represents three-quarters of the country's storage capacity. It is owned and operated by former incumbent Centrica Storage.

The maximum daily deliverability from storage is 135 mcm/d following the expansion of the Aldbrough facility and the start-up of the E.ON facility at Holford. This is around one-quarter of the National Grid's peak-demand estimate (511 mcm/d for winter 2013-14) and 29% of the highest actual demand (465 mcm/d) recorded in January 2010. On average, gas storage makes up about 10% of the overall gas supply mix over the winter period (October to March).

Emergency policy

The United Kingdom has a market-based regulatory regime for the natural gas sector. In normal conditions the country relies on the market to maintain security of supply. The DECC, Ofgem and NGG work together to closely monitor gas security of supply.

In the event of an emergency, the country has a specific emergency response plan – the National Emergency Plan for Gas and Electricity (NEP-G&E). The NEP-G&E sets out the arrangements between the gas and electricity industries, and the DECC, for the safe and effective management of gas and electricity supply emergencies in the United Kingdom. (Separate arrangements are in place for Northern Ireland.) The NEP-G&E includes provision for the use of emergency powers under the Energy Act 1976, which would only be activated in significant emergencies. The plan applies to the two forms of supply:

- electricity supply network from generator to consumer's meter or electricity supply terminal
- downstream gas supply network from reception terminal or storage site to customer isolation valve.

Emergency response measures

In the event of a natural gas supply disruption, the Network Emergency Coordinator (NEC) would co-ordinate emergency response measures across the affected parts of the gas network. The NEC is an independent body that is also responsible for declaring a network gas supply emergency and for authorising the strategy proposed by the NGG to resolve the emergency. This is implemented under industry arrangements independent of the NEP-G&E. Large industrial gas users are directed to cease all use or, for protected sites under the Gas Priority User Arrangements, to reduce their gas demand significantly, with the aim of maintaining safe minimum pressures within the gas network. The last customers to be affected would be residences. A volume of gas must be maintained in storage to protect certain vulnerable customers, such as households and hospitals, against a "1 in 50" winter.

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Fuel switching in power generation is the most common response to reductions in the natural gas supply. In these circumstances natural gas is generally replaced by coal or, where possible (as in the case of combined-cycle gas turbines) with distillate. Interruptible supply contracts in the industrial and commercial sectors also provided an estimated maximum daily interruptible gas capacity of about 36 bcm in 2010.

To complement these market procedures, commercial storage capacity has increased by around 25% in the past decade. Deliverability (the rate at which gas can be supplied to the network), has also increased from 100 mcm to 135 mcm/d. The United Kingdom has also enhanced and diversified its import infrastructure, and remains a large (although declining) producer.

The market is able to respond to periods of high demand by increasing imports and storage flows to meet demand without any intervention (such as from the National Grid).

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United States

Key data

Table 4.29.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	8 945.5	8 024.0	7 081.8	7 775.4	8 130.3	9 171.4	11 920.4
Demand (kb/d)	17 201.0	19 998.9	21 167.6	19 476.5	19 248.1	18 907.4	18 500.3
Motor gasoline	7 286.8	8 533.4	9 232.0	9 051.7	8 812.2	8 770.1	-
Gas/diesel oil	3 051.3	3 787.7	4 203.3	3 869.5	3 968.5	3 814.3	-
Residual fuel oil	1 281.8	992.4	1 019.6	615.9	542.5	424.5	-
Others	5 581.1	6 685.5	6 712.6	5 939.4	5 924.9	5 898.5	-
Net imports (kb/d)	8 255.5	11 974.9	14 085.8	11 701.1	11 117.8	9 736.0	6 579.9
Import dependency (%)	48.0	59.9	66.5	60.1	57.8	51.5	36
Refining capacity (kb/d)	15 572.0	16 511.9	17 124.9	18 356.3	18 356.3	18 356.3	-
Oil in TPES (%)**	40	38	40	36	36	36	-

* Forecast.
** TPES data for 2012 are estimates.

Table 4.29.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	506 604	544 335	511 486	603 857	648 758	681 385	796 749
Demand (mcm/y)	530 159	661 261	623 171	683 107	691 037	720 862	791 601
Transformation	108 785	166 772	187 648	225 879	231 833	0	-
Industry	150 045	189 223	147 279	157 199	157 396	0	-
Residential	124 327	141 614	136 679	135 425	133 478	0	-
Others	147 002	163 652	151 565	164 604	168 330	0	-
Net imports (mcm/y)	23 555	116 926	111 685	79 250	42 279	39 477	- 5 148
Import dependency (%)	4.4	17.7	17.9	11.6	6.1	5.5	- 1
Natural gas in TPES (%)	23	24	22	25	26	28	-

* 2012 data are estimates.
** Forecast.

Note: This section on the emergency response systems of individual member countries was written by the IEA. All countries provided valuable information and comments. All opinions, errors and omissions are solely the responsibility of the IEA.

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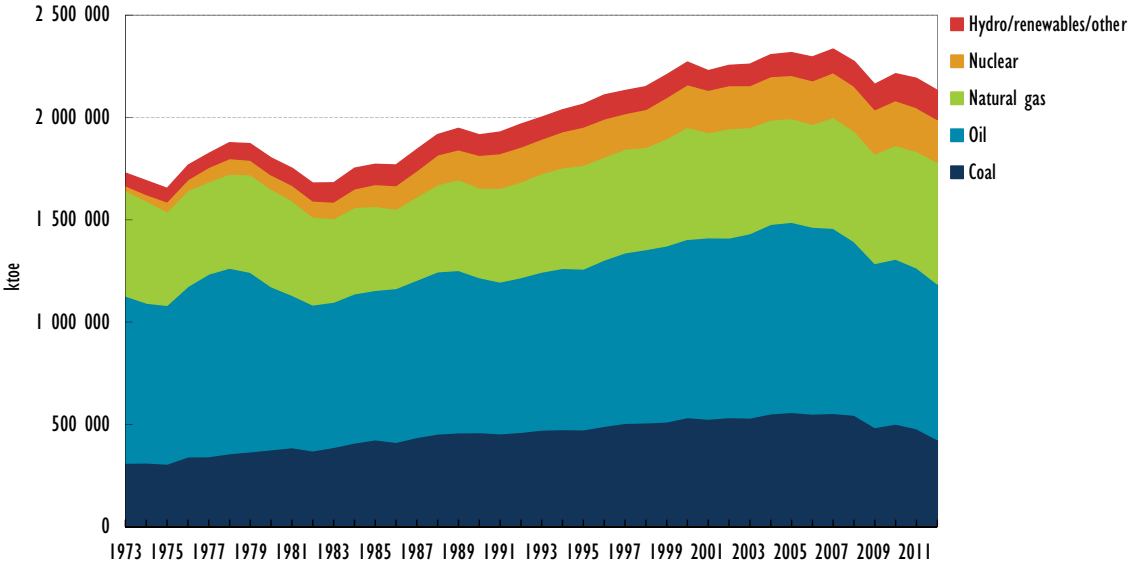
Figure 4.29.1 Total primary energy source (TPES) trend, 1973-2012



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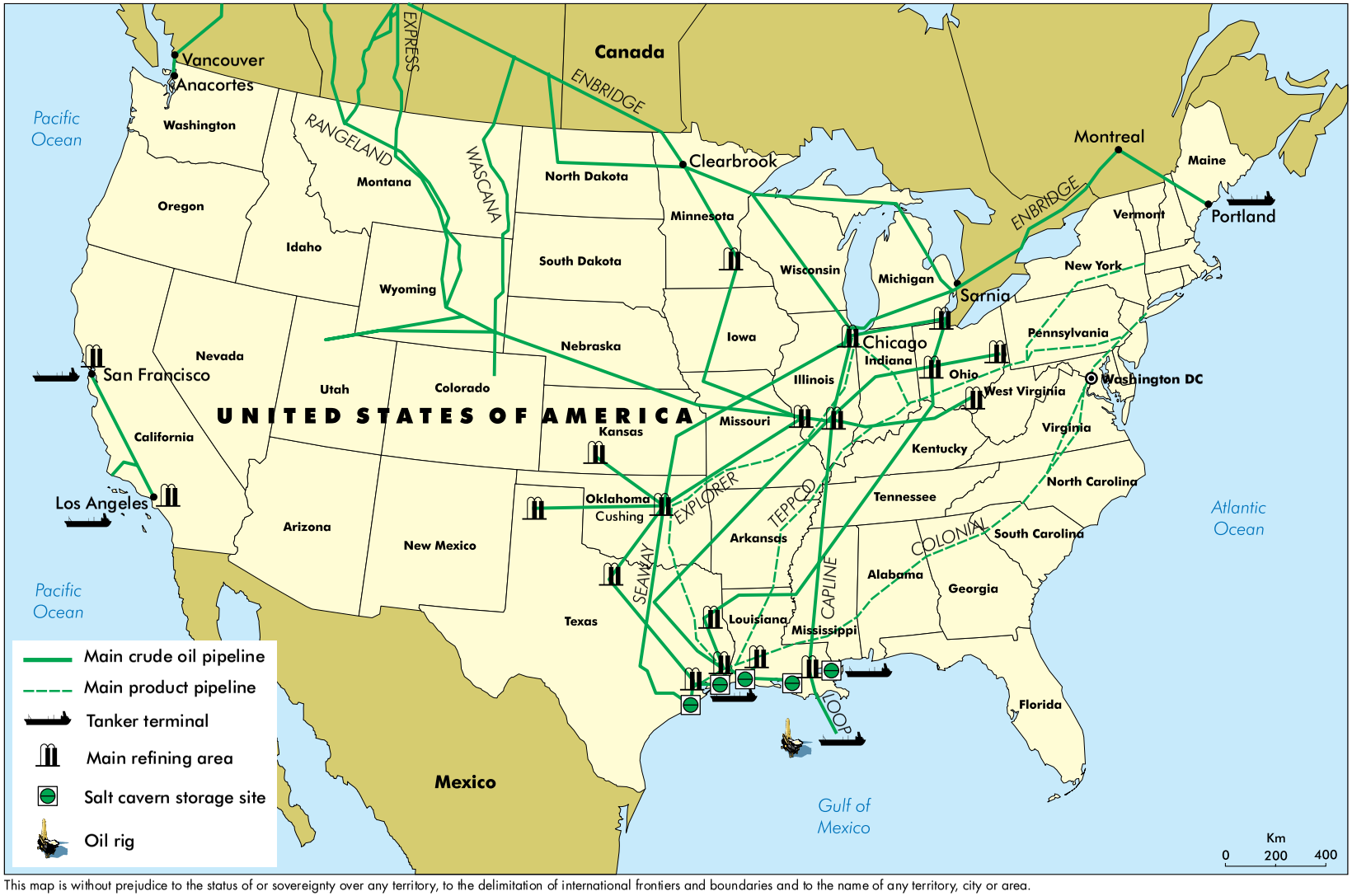
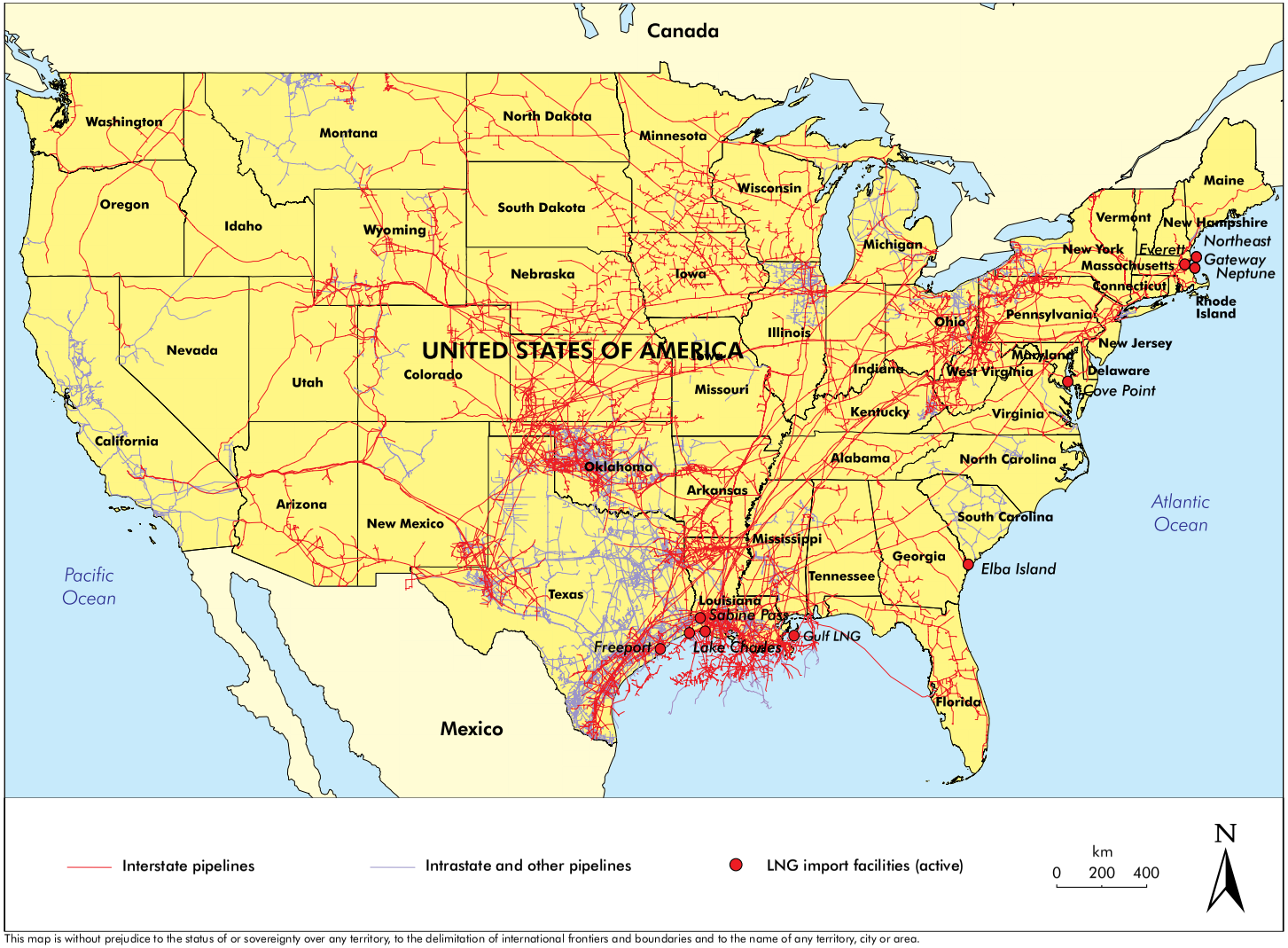
Map 4.29.1 Oil infrastructure of the United States



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Map 4.29.2 Gas infrastructure of the United States



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Country overview

Oil remains the most significant (although declining) energy source in the United States, accounting for 36% of the country's total primary energy supply (TPES) in 2012. US oil demand was 18.9 million barrels per day (mb/d) in 2012, down from 19.3 mb/d in 2011 – and continuing a general downward trend since 2007. The road transport sector is the largest single consumer of oil in the United States, accounting for 70% of total consumption in 2011 – with gasoline alone accounting for 46% of oil product demand in 2012. US oil demand is expected to remain relatively flat in the medium- to long-term.

The United States has substantial domestic oil production – equivalent to over 57% of consumption in 2012. Crude oil production increased from around 5 mb/d in 2008 to nearly 6.5 mb/d in 2012. Domestic production is forecast to continue rising sharply, with an average production growth rate of 234 kb/d until 2019 when it is expected to peak at 7.5 mb/d. The increase in oil production is largely thanks to new technologies such as horizontal drilling that, when used in conjunction with hydraulic fracturing, have brought domestic resources into production that were previously considered nonviable.

With regard to oil imports, US imports totalled 11.1 mb/d in 2012 (down from 11.9 mb/d in 2011) – including 8.75 mb/d crude oil and 1.2 mb/d of products such as gasoline, diesel, heating oil and jet fuel. The country also exported around 3 mb/d of products – making it a net exporter of petroleum products (nearly 1.3 mb/d in 2012). The United States has widely diversified import sources. Canada is by far the biggest exporter of oil and petroleum products to the United States, followed by Saudi Arabia, Venezuela and Mexico.

As of April 2013 the United States meets its 90-day International Energy Agency (IEA) stockholding obligation solely with public stocks (696 million barrels of crude oil) held in the Strategic Petroleum Reserve (SPR). Prior to April 2013 the country relied on industry stocks held for commercial purposes in addition to SPR stocks to meet its 90-day obligation. This development is caused by declining US net-import levels as a result of growing domestic oil production and declining oil imports.

The government's preferred response to an oil supply disruption is to release stocks from the SPR. However, the country has other statutory mechanisms for use in certain situations such as natural disasters, for example hurricanes.

The share of natural gas in the country's TPES was 28% in 2012, up from 26% in 2011 and 25% in 2010. The share of natural gas had been in steady decline since the early-1970s, but the past couple of years have seen a rapid reversal of this trend. Sources of demand in the United States are relatively diverse, with electricity generation, the industrial sector and road transport all expected to drive future demand growth thanks to low natural gas prices.

Domestic natural gas production was sufficient to cover 95% of domestic demand in 2012, with only around 5% of demand met through imports. Gas production has grown rapidly in recent years, largely owing to surging shale gas production, and is expected to continue to grow faster than consumption. Forecasts indicate that the country will become a net exporter of natural gas by 2018.

The United States has a high degree of natural gas infrastructure reliability underpinning its security of supply, including the diversification of supply routes and substantial storage capacity. The country's supply security is further enhanced by the fact that border crossing points have "reverse flow" capacity that can be used when needed.

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Oil

Market features and key issues

Domestic oil production

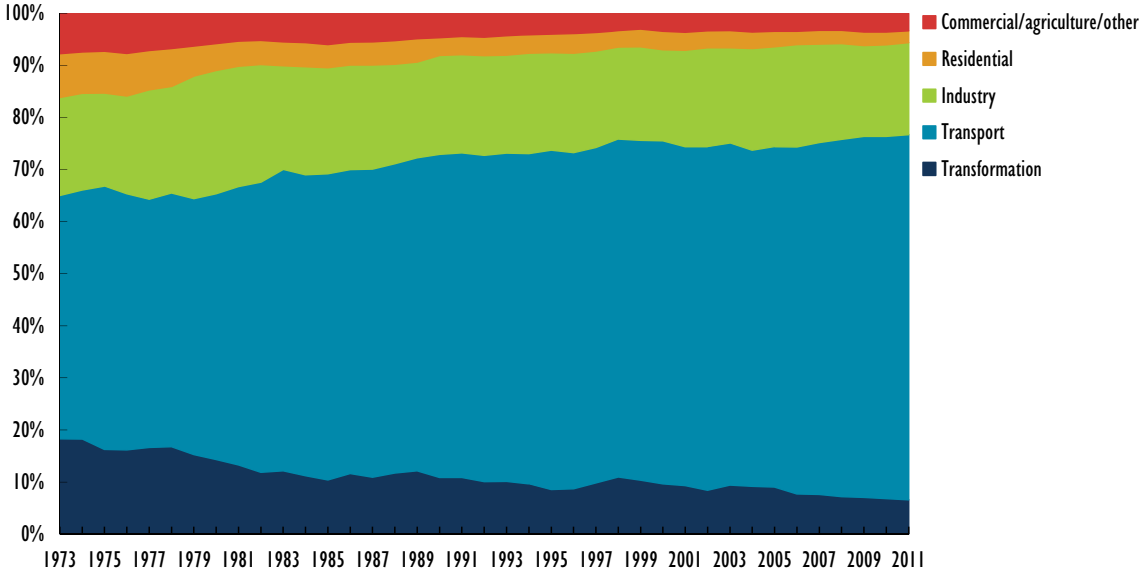
Oil remains the most significant (although declining) energy source in the United States, accounting for almost 36% of the country's TPES in 2012. Importantly, the US has substantial domestic oil production – equivalent to over 57% of its oil consumption in 2012. The level of domestic crude oil production has increased over the past few years, reversing a decline that began in 1986. According to IEA figures, crude oil production increased from 5 mb/d in 2008 to just under 5.7 mb/d in 2011 and 6.5 mb/d in 2012. This increase in oil production is largely created by the application of new horizontal drilling technology and hydraulic fracturing, bringing domestic resources into production that were previously considered nonviable.

According to the US Energy Information Administration's (EIA) *Annual Energy Outlook 2013* (*AEO 2013*) base case scenario, domestic production is forecast to continue rising sharply, with an average production growth rate of 234 kb/d until 2019 when crude production is expected to peak at 7.5 mb/d. After 2020 a gradual production decline is forecast, but crude levels are expected to remain above 6 mb/d until at least 2040.

Oil demand

The United States is the largest consumer of oil in the world, and accounts for around 42% of the total oil consumed by IEA member countries. In 2012, US oil demand was 18.9 mb/d, down from 19.3 mb/d in 2011 – continuing a general downward trend that began in 2007. The road transport sector is the largest single consumer of oil in the US. Transport consumed 70% of total oil supply in 2011, with gasoline alone accounting for 46% of oil product demand in 2012 (up slightly from 43% in 1997). Industry was a distant second at 18% of total oil consumption in 2011. Its share has been relatively constant over the past decade and longer.

Figure 4.29.2 Oil consumption by sector, 1973-2011



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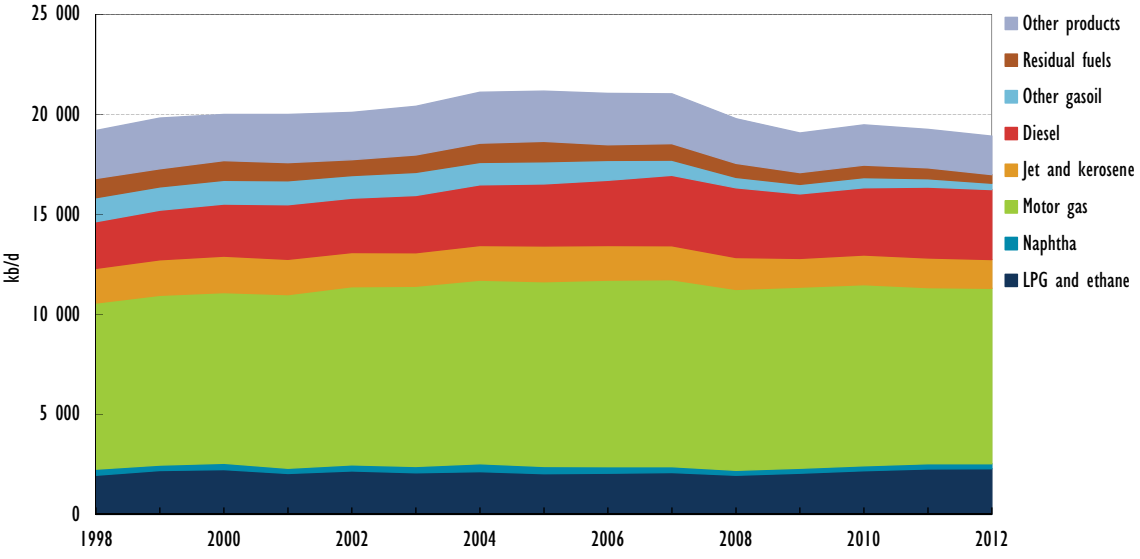
US oil consumption is expected to remain relatively flat in the medium- to long-term. This is largely because of an expected decline in demand from the transport sector, with *AEO 2013* projecting a 0.9% decrease in motor gasoline consumption from 2011 to 2040. Increasing vehicle efficiency is projected to reduce gasoline use in the transportation sector by 500 kb/d in 2025 and 1 000 kb/d in 2035. In addition, some petroleum-based diesel fuel consumption is expected to be offset by increased use of liquefied natural gas (LNG) for heavy-duty vehicles (because of the improving economics of LNG) and the increased use of diesel produced using gas-to-liquids (GTL) technology.

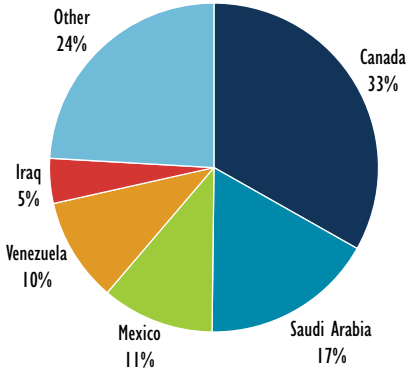
Figure 4.29.3 Oil demand by product, 1998-2012



Imports/exports and import dependency

According to IEA figures, US oil imports totalled 11.1 mb/d in 2012 (down from 11.9 mb/d in 2011). This figure includes 8.75 mb/d of crude oil and 1.4 mb/d of products such as gasoline (0.72 mb/d), diesel, heating oil and jet fuel. The country also exported around 3 mb/d of products, including 1.2 mb/d of pruducts such as gasoline, diesel, heating oil and jet fuel, making it a net exporter of products (nearly 1.3 mb/d in 2012). Net US imports of crude oil and petroleum products in 2012 totalled 7.968 mb/d.

Figure 4.29.4 Crude oil imports by origin, 2012



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The United States has widely diversified import sources, with Canada accounting for 29% of its crude oil imports in the fourth quarter of 2012, followed by Saudi Arabia (17%), Mexico (13%) and Venezuela (16%). A total of 47.4% of crude oil imports came from OPEC countries in 2012 – notably Saudi Arabia, Nigeria and Venezuela. The United States is a net exporter of petroleum products but still imports significant amounts of some products (e.g. LPG) – 62.5% of which come from OECD member countries.

Increased domestic production is having a significant impact on oil imports. According to IEA figures, oil and product imports as a share of US oil consumption peaked at 66.5% in 2005 before dropping to around 60% in 2010 and 51% in 2012. Import dependency is expected to continue to fall in the short to medium term, with import dependency expected to drop to 36% by 2018.

US government figures show an even greater decrease in dependency on imports. According to government figures, imported liquid fuels as a share of US liquid fuel consumption peaked at 60% in 2005 before dropping below 50% in 2010 and declining further, to 45% in 2011. AEO 2013 projections indicate that the share of imported liquid fuels will continue to decline in the medium term, reaching 34% in 2019, before rising to 37% in 2040 owing to the expected slow decline in domestic tight oil (shale oil) production beginning around 2020.

In March 2011, the President of the United States set a goal for the country to reduce its dependence on oil imports by one-third (relative to their level when the president took office – i.e. 11 mb/d) by 2025. However, the US oil import outlook is changing so quickly that the goal was later revised to reducing oil imports by half by 2020.

Oil company operations

The United States has a largely deregulated and competitive oil market. All the companies operating in the US oil sector are privately owned apart from the SPR and the Northeast Home Heating Oil Reserve (NEHHOR).

Oil supply infrastructure

Refining

In 2012 the US refining sector had 145 operational refineries with a combined capacity of 17.3 mb/d and an operable utilisation rate of 88.7%. The country has a relatively good balance between refinery output and domestic product demand, and the United States is a net product exporter.

The key category of surplus product is middle distillates (particularly diesel), while the main products where demand exceeds production are liquefied petroleum gas (LPG) and ethane, naphtha and residual fuels. Most US refineries are configured for maximum distillate output and have consequently received a competitiveness boost from low natural gas prices as natural gas is used as a hydrocracker feedstock.

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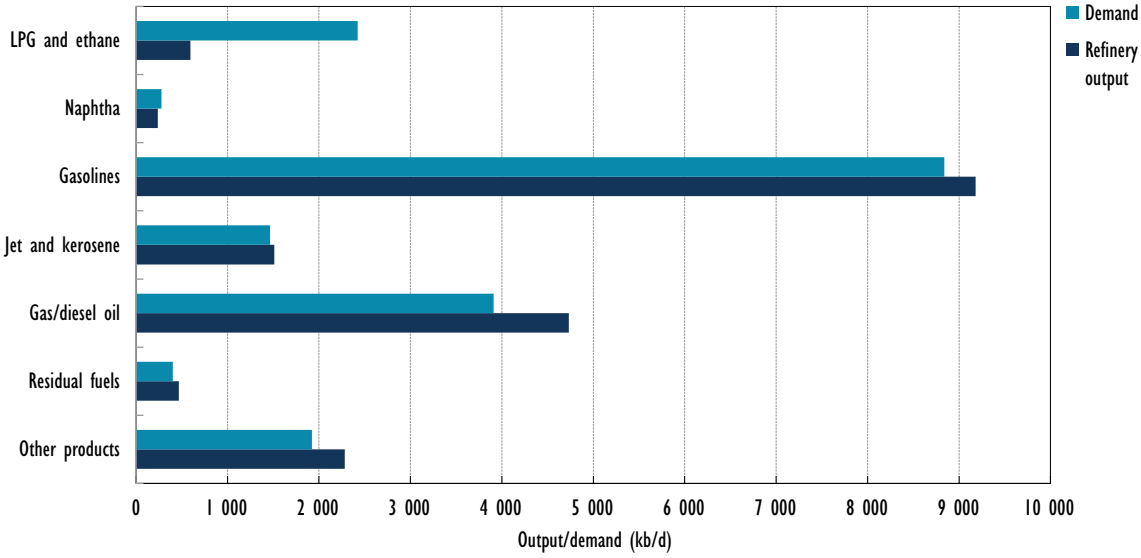
Figure 4.29.5 Refinery output vs. demand, 2012



There are five new refineries proposed for the United States, all of which (if they go ahead) are intended to utilise Bakken tight oil production which is made up of sweet crude grades. Bakken production has also revitalised the competitiveness of many east coast refineries as these are configured for sweet crude grades and were until recently dependent on more expensive imported Brent Crudes. The Gulf Coast refining sector is not so well positioned to benefit from new domestic production as many of its refineries are configured for heavy crude grades. Some Gulf Coast refiners are planning to alter their configuration to process lighter crudes such as those from the nearby Eagle Ford Play, while others may benefit from increased supplies of heavier Canadian crudes if the necessary pipeline infrastructure is built to bring this crude south in sufficient quantities.

Ports and pipelines

There are a significant number of oil ports around the US. Most have import terminals for crude and product imports, but a small number only take product imports.

Pipelines are the most commonly used mode of transport for shipping crude oil in the United States. The US has 172 048 miles of crude gathering and distribution pipelines operated by 2 338 companies, with the top ten operators alone responsible for nearly 55 000 miles of pipeline. According to the EIA, in 2011 the US domestic pipeline network transported 514.3 mb/d of crude oil between regions. The highest concentration of pipelines in the United States is in the Gulf Coast region (which also has nearly 50% of the country's refining capacity). The largest crude pipelines in the United States were constructed to move oil between the Gulf Coast and the midwest regions.

As is the case with crude oil, pipelines are the most commonly used mode of transportation for shipping refined products in the US. The EIA reported that nearly 1.695 billion barrels of petroleum products were transported via inter-regional pipelines in 2011. Four major pipeline systems from the Gulf Coast provide products to the east coast and midwest regions of the United States. Another major pipeline system transports petroleum products on the US West Coast.

Rail is another rapidly growing mode of transportation for US crude oil and petroleum products. It is mainly used for transportation of oil where there is a lack of pipelines,

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where existing pipelines lack sufficient available capacity, or where rail is the most cost-effective option.

Storage capacity

The total operating shell storage capacity of the United States as of 30 September 2012 was 2.18 billion barrels, including the 727-million barrel capacity of the SPR.

Decision-making structure

US oil emergency response policies are based primarily on the Energy Policy and Conservation Act (EPCA). The EPCA gives the US president the authority to direct a drawdown of the SPR in the event of a "severe energy supply interruption", or to meet US obligations under the International Energy Program.

The US Department of Energy (DOE) serves as the country's national emergency strategy organisation (NESO), with the responsibility of initiating and co-ordinating a US response to an oil supply disruption. The NESO is composed of two teams – the crisis assessment team and the executive team.

The crisis assessment team is led by the DOE Office of Policy and International Affairs. The team is responsible for analysis of the crisis situation and recommendations for response options to the executive team. The executive team is comprised of the secretary of energy, the deputy secretary of energy and senior management from the Office of Policy and International Affairs, the EIA and the SPR. The executive team analyses and discusses the findings of the crisis assessment team and co-ordinates a response with other departments and White House staff offices. The secretary of energy is responsible for forwarding the executive team's recommendations to the US president.

Personnel from all the offices that comprise the crisis assessment team and the executive team are required to undergo regular training to maintain their capacity to act as an effective emergency response team. At the executive level, the DOE has a protocol in place to conduct a crisis simulation, known as Oil Shockwave, to simulate an oil supply crisis. At the staff level, personnel from the Office of Petroleum Reserves and the Office of Policy and International Affairs have participated in the emergency response exercises of the IEA. Additionally, the Office of Petroleum Reserves conducts bi-annual "Eagle" and "Pride" drills to simulate large and small crisis response situations.

The government's preferred response to an oil supply disruption is to release stocks from the SPR. However, the United States has other statutory mechanisms for use in certain situations such as natural disasters (e.g. hurricanes).

Stocks

Stockholding structure

The SPR was established in 1975 under the EPCA "to reduce the impact of disruptions in supplies of petroleum products" and to "carry out obligations of the United States under the International Energy Program".

The SPR has a total storage capacity of 727 million barrels of crude oil, and as of April 2013 had an inventory of 696 million barrels – equivalent to 91 days of net imports. This means that the United States can now meet its 90-day IEA obligation solely with public SPR stocks. Prior to April 2013 the country also relied on industry stocks held for commercial purposes, in addition to SPR stocks, to meet its 90-day obligation. This development is the result of growing domestic oil production and declining oil import

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levels – which have led to a decline in US net imports and therefore a decline in the amount of stock required to meet the 90-day obligation.

The NEHHOR was established in 2000 (also under the EPCA). Originally established as a two-million barrel reserve, the NEHHOR inventory was converted to cleaner burning, ultra-low sulphur distillate by the DOE in 2011, and the size of the reserve was reduced to one million barrels caused by declining levels of heating oil consumption.

Crude or products

The stocks held in the SPR consist entirely of crude oil, while the NEHHOR inventory consists of low-sulphur diesel. US industry stocks are a combination of crude oil and product, with crude oil accounting for around 34% of the total.

Location and availability

The SPR consists of 62 large storage caverns in underground salt dome formations located at four sites in Texas and Louisiana along the Gulf Coast. The oil stored in the SPR is around 99% available for sale and delivery.

Monitoring and non-compliance

The DOE has overall responsibility for the management and administration of the SPR and the NEHHOR programmes. Within the DOE, the Office of Petroleum Reserves under the auspices of the Office of Fossil Energy is responsible for the management, operations and maintenance of both the SPR and NEHHOR programmes. There is no statutory obligation on industry in the United States to hold stocks for emergency purposes.

Financing and fees

The United States government has full ownership of all petroleum stocks in the SPR and NEHHOR, as well as all SPR storage facilities. These were paid for through government appropriated funds. The SPR programme employs government-owned storage facilities, using underground salt storage caverns to store crude oil stocks. The SPR is able to achieve very low operating costs because of its use of salt cavern storage technology that enables it to attain massive economies of scale. The total annual operating cost for the SPR is USD 195 million or USD 0.27 per barrel stored.

Other measures

Demand restraint

At the federal government level, oil demand restraint is not among the policy options available for use during an oil supply disruption. Rather than operating at the federal level, US oil demand restraint policies and regulations exist at the state level – and vary from state to state. The federal government allows each state to determine the scope and use of demand restraint measures, and aside from information sharing, there is little demand restraint policy co-ordination between states.

For example, during Hurricane Sandy the New York City mayor issued an Executive Order (number 163) restricting gasoline purchases to odd and even days corresponding to vehicle licence plates.

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Fuel switching

The US has no specific policies to promote fuel switching in an emergency. However, the electricity generation sector maintains significant fuel-switching capacity. The net summer capacity of petroleum-fired generators reporting the ability to switch to natural gas was 18 356 megawatts (MWs), or about 35.8% of the total in 2011 (down from 40.2% in 2010).

Other

Fuel specification waivers

The temporary waiver of mandatory fuel specifications is another potential measure for use during an oil supply disruption. If the fuel supply is disrupted because of an unforeseen emergency situation, the Environmental Protection Agency (EPA), with the concurrence of DOE, is authorised to issue a temporary fuels waiver to mitigate outages under the Clean Air Act.

Fuel waivers of this type were used during August and September 2012 after Hurricane Isaac caused a number of Louisiana refineries to be shut down for about a week – causing gasoline outages in the southeastern United States. At that time, the EPA issued a temporary waiver on summer gasoline volatility standards for the region, thereby enabling greater quantities of gasoline to be produced to mitigate the supply outages. Various fuel and environmental waivers were also used in October 2012, in the aftermath of Hurricane Sandy.

Surge production

The United States does not retain the potential to surge oil production during an emergency. Domestic oil production in the United States is already taking place at the maximum feasible rates.

Gas

Market features and key issues

Gas production and reserves

Domestic production was sufficient to cover 95% of US natural gas demand in 2012, with only 5% of US natural gas demand met through imports. Domestic natural gas production has grown rapidly in recent years and is expected to continue to grow faster than consumption. Forecasts indicate that the United States will become a net exporter of natural gas by 2018. It is unclear whether, or to what extent, domestic regulations will limit the quantity of natural gas that can eventually be exported from the United States.

Surging shale gas production is the key reason for ongoing rapid growth in total US natural gas production levels. Shale gas only comprises around 30% of total US natural gas production but is growing so quickly that, if production continues to increase as projected, it will offset an expected decline in production rates from conventional domestic natural gas sources.

Two reasons behind the continuing success of US unconventional gas production, despite low domestic natural gas prices, are high crude prices, which significantly improve the economics of natural gas plays that have a high liquids content, and improved drilling efficiencies, which result in a greater number of wells being drilled more quickly, with

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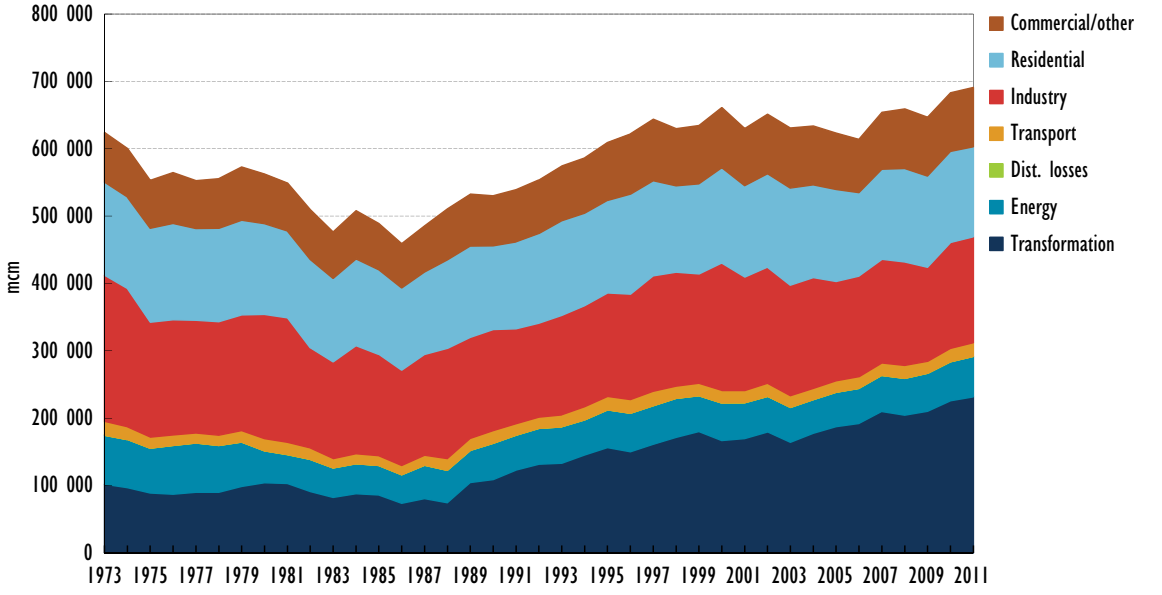
fewer rigs and higher initial production rates. This last point also illustrates the fact that technologies like hydraulic fracturing are still relatively new and continuing to develop, so there are no guarantees that the current per unit cost of developing the resource and current high production rates can be sustained over the long term. Despite optimistic supply and demand projections in the *AEO 2013* "reference case" scenario, future consumption forecasts are highly sensitive to pricing which is in turn highly sensitive to estimated ultimate recovery rates.

Gas demand

According to IEA figures, US consumption of natural gas was 691 bcm in 2011 (estimated to have increased to 721 bcm in 2012). This figure is projected to reach almost 792 bcm by 2018 and to continue to increase for the foreseeable future.

Figure 4.29.6 Natural gas consumption by sector, 1973-2011



Sources of natural gas demand in the US are quite diverse – with electricity generation, the industrial sector and the road transport sector all expected to drive future demand growth thanks to low natural gas prices.

The proportion of electricity generated from natural gas reached 25% in 2011 according to government figures[6], up from 24% in 2010 and 16% in 2000. This trend is expected to continue with the proportion of electricity generated from natural gas projected to reach 27% by 2020 and 30% in 2040.

Natural gas use in the industry sector is expected to increase by 16%, from 192.5 bcm per year in 2011 to 220.8 bcm per year in 2025. Increased demand for natural gas for industrial production (particularly in the bulk chemicals and primary metals sectors) is being driven by an extended period of relatively low natural gas prices, which lower the costs of both raw materials and energy. Natural gas consumption is also expected to grow in the transport sector where LNG will increasingly be used as a fuel for heavy-duty trucks, and natural gas will increasingly be used as a feedstock for producing diesel and other liquid fuels.

6. *Electric Power Monthly*, February 2013.

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Gas import dependency

The share of natural gas in the country's TPES was 28% in 2012, up from 26% in 2011 and 25% in 2010. Domestic production was sufficient to cover more than 95% of US natural gas demand in 2012, with only 5% of demand met through imports. Most US natural gas imports (94% in 2012) are sourced from Canada, with another 4% from Trinidad and Tobago.

Gas company operations

The US natural gas market is dynamic and highly competitive, with a very active spot and futures market. The industry has a high degree of private ownership with little vertical integration. Production, transmission and distribution are usually separate entities with limited examples of upstream or downstream integration – although some large gas distributors own transmission pipelines. The only public ownership in the US gas industry is in gas distribution.

Gas supply infrastructure

Ports and pipelines

The US natural gas pipeline network is a highly integrated transmission and distribution grid that can transport natural gas to and from nearly any location in the lower 48 States. There were 38 active entry/exit points for pipeline imports/exports and ten active entry/exit points for LNG imports/exports in 2011, totalling 48 total entry/exit points. Natural gas may, and sometimes does, flow in both directions; however, at each of these sites the flow is either primarily import or export.

Eight active entry points receive about 90% of all US natural gas imports. Canadian imports via Port of Morgan, Eastport, Noyes, Sherwood and Sumas accounted for 83% of total pipeline imports. The most active entry point for LNG imports is Everett, Massachusetts which represents 39% of total LNG imports.

Several major new natural gas pipelines have been completed in the United States since 2007. However, according to the government, natural gas futures contract prices signal that additional natural gas pipeline capacity may be needed to reduce peak winter premiums further in big winter load centres such as New York City and Boston that remain subject to pipeline constraints.

Overall, the United States has a high degree of natural gas infrastructure reliability, including the diversification of supply routes and substantial storage capacity. The country's gas supply security is further enhanced by the fact that border crossing points have reverse flow capacity that can be used when needed.

Storage

The United States has 411 natural gas storage facilities with a total capacity of 120 bcm. The facilities are widely dispersed geographically and consist of a combination of salt caverns (37), aquifers (43) and depleted reservoirs (331). The advantage of significant amounts of salt cavern storage is that it allows rapid injection and withdrawal to respond to market conditions and other short-term events.

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Emergency policy

The US government does not hold strategic reserves of natural gas or place a minimum natural gas stockholding obligation on industry.

The US president (or delegated authority) is authorised under the Natural Gas Policy Act 1978 (NGPA) to declare, and respond to, a natural gas supply emergency. The president has retained the authority to declare an emergency, but has assigned all other responsibilities associated with natural gas emergency response to the secretary of energy – who in turn has delegated them to the deputy secretary of energy. The Secretarial Delegation Order to the deputy secretary states that he will "carry out the functions under Sections 302 through 304(c) of the NGPA [...] after consultation with the Assistant Secretary for Fossil Energy and with the heads of other Executive departments and agencies".

The emergency provisions under the NGPA include emergency purchase and emergency allocation authorities. These are to be used for the purpose of protecting high priority users of natural gas, where an interruption of supply could endanger lives, health or the maintenance of physical property.

Other legislation relevant to natural gas emergency policy includes the International Emergency Economic Powers Act, EPCA and the Natural Gas Act.

In the event of an unusual or extraordinary threat, the US president is authorised by the International Emergency Economic Powers Act to declare a national emergency and to investigate, regulate or prohibit the import or export of any property (including natural gas) in which any foreign country or foreign national has an interest by any person or with respect to any property subject to US jurisdiction.

The EPCA provides the US president with additional independent rule-making authority to restrict natural gas exports.

The DOE is authorised (subject to a hearing at which good cause must be demonstrated) by Section 3 of the Natural Gas Act to issue supplemental orders that modify or rescind prior orders to import or export natural gas to protect the public interest. The DOE is also authorised by Section 16 of the Natural Gas Act to "perform any and all acts and to prescribe, issue, make, amend and rescind such orders, rules and regulations as it may find appropriate" to carry out its responsibilities.

Under the national response framework developed by the Department of Homeland Security, DOE will facilitate the restoration of damaged energy systems and components when activated by the Secretary of Homeland Security for incidents requiring a co-ordinated federal response. Under DOE leadership, Emergency Support Function No. 12 (Energy) is an integral part of the larger DOE responsibility of maintaining continuous and reliable energy supplies for the United States through preventive measures and restoration and recovery actions.

Emergency response measures

The US government has no demand restraint policies in place at the federal level for use during a natural gas supply disruption. However, the federal government has provided grants to state energy offices to develop energy emergency response plans, including natural gas allocation and demand restraint policies and associated regulations. The DOE maintains a mechanism whereby it can work effectively with individual states during an emergency – as demonstrated in the case of Hurricane Sandy.

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The United States government has no policies in place to promote fuel switching away from natural gas in an emergency. However, the electricity generation sector has significant fuel-switching capacity.

Likewise, the United States government has no policies in place to promote surge production or interruptible contracts as natural gas emergency management tools.

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Emergency response systems of IEA partner countries

Recognising that oil consumption and net imports in some non-member IEA economies are increasing rapidly, the IEA promotes dialogue and information-sharing on oil security policies; it also shares information and experience about creating national emergency oil stocks with key transition and emerging economies, such as China, India and the countries of the Association of Southeast Asian Nations (ASEAN). Expanding international co-operation with all players in global energy markets to improve market transparency through the collection of more accurate and timely data is also a critical component of the work of the IEA towards greater energy security.

This chapter provides a profile of the emergency response systems of China and India, countries belonging to ASEAN and a detailed overview of Chile, an IEA candidate country. As in the previous chapter, much information in this chapter is based on Emergency Response Assessments (ERAs) or reviews conducted in several of the countries represented: notably Chile (2011) and India (2013).

The profiles are presented in the following general sequence, subject to the availability of data in particular cases:

Key data

Key oil data, 1990-2018

Key natural gas data, 1990-2018

Total primary energy source trend, 1973–2012

Infrastructure map

Country/regional overview

OIL

Market features and key issues
Domestic oil production
Oil demand
Refining
Imports/exports and import dependency
Oil company operations
Oil supply infrastructure
Refining
Ports and pipelines
Storage capacity
Decision-making structure

Stocks
Stockholding structure
Crude or products
Location and availability
Monitoring and non-compliance
Stock drawdown and timeframe
Financing and fees
Other measures
Demand restraint
Fuel switching
Other

GAS

Market features and key isuses
Gas production and reserves
Gas demand
Gas import dependency

Ports and pipelines
Storage
Emergency policy
Emergency response measures

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Association of Southeast Asian Nations (ASEAN)

Key data

Table 5.1.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	2 441	2 844	2 811	2 657	2 567	2 554	2 436
Demand (kb/d)	2 140	3 670	4 428	5 422	5 666	5 827	6 737
Net imports (kb/d)	- 301	826	1 617	2 765	3 099	3 273	4 301
Import dependency (%)	- 14	23	37	51	55	56	64
Oil in TPES (%)**	38	40	38	36	37	-	-

* Forecast.
** TPES data for 2012 are estimates.

Table 5.1.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	81 587	154 208	192 435	203 370	203 370	201 786	226 000
Demand (mcm/y)	33 463	84 654	120 724	143 382	143 382	148 742	184 000
Net imports (mcm/y)	- 48 124	- 69 554	- 71 711	- 59 988	- 59 988	- 53 044	- 42 000
Import dependency (%)	- 144	- 82	- 59	- 42	- 42	- 36	- 23
Natural gas in TPES (%)	13	19	22	22	21	-	-

* 2012 data are estimates.
** Forecast.

Note: This section on ASEAN was written by the IEA, based on public information, IEA statistics, press reports and reports from various energy analysts, and does not represent the official view of the ASEAN governments. All errors and omissions are solely the responsibility of the IEA.

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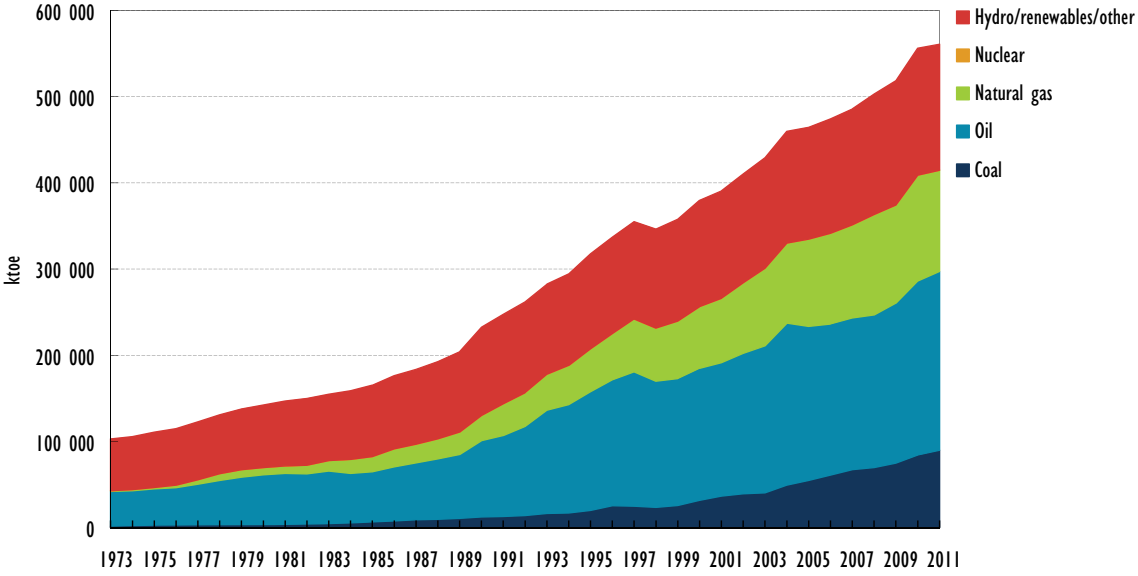
Figure 5.1.1 Total primary energy source (TPES) trend, 1973-2012



Note: unless otherwise indicated, all tables and figures in this chapter derive from IEA data and analysis.

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Map 5.1.1 Oil infrastructure of ASEAN

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Map 5.1.2 Gas infrastructure of ASEAN

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Regional overview

The Association of Southeast Asian Nations (ASEAN) is a geopolitical and economic organisation of countries located in Southeast Asia, which was founded in 1967. ASEAN includes ten member states: Brunei Darussalam, Cambodia, Indonesia, The Lao People's Democratic Republic, Malaysia, Myanmar, Philippines, Singapore, Thailand and Viet Nam. The aims of ASEAN are the acceleration of economic growth, social progress, cultural development and energy security. Although some ASEAN member states are net oil exporters and others are net oil importers, all member states recognise the importance of energy security for their economic growth.

The TPES of ASEAN was over 560 million tonnes of oil equivalent (Mtoe) in 2011, or 4.3% of global demand. Oil remains the dominant fuel with a 37% share in the primary energy mix. Natural gas is second at 21% of the TPES, while ASEAN coal use has been rising at double-digit rates since 1990, tripling its share of the energy mix to 16%.

Southeast Asia is a mature oil-producing region, with most countries facing the decline of their large mature oil fields and having limited large new prospects. While regional oil production was around 2.6 million barrels per day (mb/d) in 2012, it is estimated that in the long term the region's output is declining slowly, dropping to 2.4 mb/d in 2018 and 1.7 mb/d in 2035. On the other hand, supported by its strong economic and population growth, the region's oil demand is estimated to rise progressively from 5.7 mb/d in 2012 to 6.7 mb/d in 2018.

In response to sharply growing oil demand and import dependence, ASEAN countries have been developing various national energy policies and programmes. While most ASEAN countries rely on industry stockholding obligations, Myanmar and Viet Nam hold a certain amount of government oil stocks. Thailand, Lao PDR and Indonesia have also been discussing the possibility of establishing public emergency oil stocks.

As oil security and emergency preparedness issues have been an integral part of their common agenda since the creation of ASEAN, ASEAN countries have established a regional treaty known as the ASEAN Petroleum Security Agreement (APSA). Its frameworks for regional consultations and co-ordination are designed to facilitate oil allocation in case of emergency; such assistance will be made on a voluntary and commercial basis.

Southeast Asia's natural gas production has surged from 154 billion cubic metres (bcm) in 2000 to an estimated 202 bcm in 2012. Natural gas production in the region is expected to reach 226 bcm in 2018 and 260 bcm in 2035. At the same time, regional demand for natural gas has increased rapidly, from 85 bcm in 2000 to around 149 bcm in 2012. It is expected to reach 184 bcm in 2018 and 250 bcm in 2035.

Combined net natural gas exports of the ASEAN countries (including trade among them) stood at 62 bcm in 2012; the natural gas mainly came from Indonesia, Malaysia, Myanmar and Brunei Darussalam. Despite increasing gas production, their combined net gas exports are expected to decrease to 14 bcm by 2035, even though the region remains a net exporter of natural gas.

As most ASEAN countries are net exporters of natural gas, an emergency policy for natural gas disruption has not been highly prioritised in the region. However, together with declining output, increasing domestic natural gas use has led countries to consider formulating emergency response mechanisms. While supporting projects to explore offshore natural gas fields, some countries have started strengthening their regasification capacity and storage facilities by building up liquefied natural gas (LNG) receiving terminals.

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Oil

Market features and key issues

Oil production

Southeast Asia is a mature oil-producing region, with most countries facing decline in large mature oil fields and having limited large new prospects.

Southeast Asia had 12.9 billion barrels in proven crude oil reserves at the end of 2012. Its oil production was around 2.6 mb/d in 2012. By country, Indonesia is the largest oil-producing country in the region, producing some 890 kb/d (35% of regional production) followed by Malaysia (26%), Thailand (17%) and Viet Nam (14%).

It is estimated that in the long term the region's output will decline slowly, dropping to 2.4 mb/d in 2018 and 1.7 mb/d in 2035. At the end of the projection period, Indonesia will remain the largest producer, followed by Malaysia and Viet Nam.

Oil demand

Supported by strong economic and population growth, the ASEAN's oil demand is estimated to rise progressively from 5.7 mb/d in 2012 to 6.7 mb/d in 2018. Oil is expected to remain the region's largest contributor to primary energy demand towards 2035, but a continued switching away from oil in power generation and industry will reduce its share of the energy mix from 38% to 31%, together with improvements in end-use efficiency and more use of biofuels to offset some of the strong growth in transport sector demand.

In 2011, transport consumed half of ASEAN's total oil demand. The sector continues to underpin fast-rising oil consumption with a further expansion of vehicle ownership, insufficiently-developed public transport and oil product subsidies.

By country, Indonesia's oil demand will rise from 1.6 mb/d in 2012 to some 1.9 mb/d in 2018. In Thailand, the country's demand for oil will rise from 1.2 mb/d in 2012 to 1.4 mb/d in 2018. Malaysian oil demand is also expected to increase from 720 kb/d in 2012 to 850 kb/d in 2018. Viet Nam's oil demand will reach 660 kb/d in 2018 compared with around 480 kb/d in 2012.

Refining

In 2012, Southeast Asia had a combined refining capacity (including crude distillation units and condensate splitters) of just over 4.9 mb/d. Singapore is an important refining and product trading hub in the region, with 1.3 mb/d of refining capacity. In 2012, its refining sector supplied the region with significant oil product exports (gasoline and fuel oil in particular), notably to Malaysia, Australia and China.

Thailand also has a total refining capacity of 1.3 mb/d (including relatively smaller refineries), followed by Indonesia with capacity of 1.2 mb/d in 2012. Indonesia's refineries operated at less than 70% of their capacity in 2012, and the country remained a large importer of oil products, especially of gasoline. Malaysia's refining capacity of 590 kb/d is enough to make it self-sufficient in meeting demand for refined oil products. Viet Nam had one operating refinery with a capacity of 149 kb/d at the end of 2012, which is well below domestic demand for refined oil, and makes the country dependent on imports.

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In the medium term, several projects have been proposed to increase regional refining capacity, including in Viet Nam, Malaysia, Brunei Darussalam and Indonesia. Towards the end of the timeframe from 2013 to 2018, Viet Nam could increase its capacity by 200 kb/d and Malaysia by 300 kb/d.

Imports/exports and import dependency

Strong economic and population growth drives fast-increasing oil demand across the region, which has led to increased imports. With oil demand expected to continue to grow across Southeast Asia, declining crude production will push the growth of oil imports.

The region's net imports of oil stood at over 3 mb/d in 2012. They are projected to increase to just over 4 mb/d in 2018. Given the expectation of higher oil prices, as well as oil product subsidies in some countries, rising oil imports will be an increasing economic burden and may leave countries more vulnerable to potential disruptions.

By country, Indonesia's net imports will rise from 700 kb/d in 2012 to around 1.1 mb/d in 2018. Thailand's net imports were over 800 kb/d in 2012, and its net imports are expected to reach 1 mb/d in 2018.

Emergency response policy and measures

Regional oil security policy developments

Co-operation in the ASEAN region is essential for improving security of oil supply in the face of future supply disruptions. Several factors provide vivid examples of the shared risks of ASEAN countries: the rapidly increasing dependence on oil imports; the significance of the Malacca Strait chokepoint for oil; and LNG imports and the potential for maritime border disputes in the South China Sea.

In response to sharply growing oil demand and import dependence, ASEAN countries have been developing various national energy policies and programmes.

At the regional level, in 1986 ASEAN countries established the APSA, a regional treaty which had as its key principle to mitigate the impact of an oil supply disruption in one or more of the ASEAN member countries by activating a sharing scheme – the ASEAN Emergency Petroleum Sharing Scheme – for crude oil and petroleum products. In 1999, ASEAN energy ministers agreed to revise the 1986 APSA in order to incorporate both short-term response measures (e.g. demand restraint, fuel switching and a co-ordinated emergency response mechanism, the ASEAN CERM), and medium and/or long-term measures (e.g. fuel mix and fuel source diversification, energy efficiency and market liberalisation). The ASEAN CERM aims to be a framework for regional consultations and co-ordination to facilitate oil allocation in case of emergency; such assistance will be made on a voluntary and commercial basis.

Status of strategic oil stockholding in ASEAN countries

ASEAN countries' national emergency preparedness policies and implementation plans continue to evolve – and reflect differences in each country's economic development, availability of indigenous resources, oil demand patterns and oil import dependency.

Although costs associated with building and holding public oil stocks are a challenge, many ASEAN countries have plans to develop government and commercial oil storage. In 2008, at the Fifth ASEAN+3 (China, Japan and Korea) Meeting in Thailand, energy

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ministers recognised the necessity of oil stockpiling initiatives in the light of persistent risks of supply disruptions and highly volatile oil markets; they welcomed activities for the development of the Oil Stockpiling Roadmap (OSRM) to support countries' initiatives for building strategic storage over the medium term.

While most ASEAN countries rely on industry stockholding obligations, Myanmar and Viet Nam hold a certain amount of government oil stocks. Thailand, Lao PDR and Indonesia have also been discussing the possibility of establishing government held stocks.

Thailand and Viet Nam have made strong commitments to achieving stock levels comparable with the 90 days of net imports held by International Energy Agency (IEA) member countries while, initially at least, other countries plan to reach lower levels of under 50 days of consumption or net imports. Whether the oil will be held by government or industry, such policy-driven storage expansions will necessitate the construction of new storage capacity.

The current status of ASEAN countries on emergency response measures is briefly described below.

Brunei Darussalam

The country has the Energy Contingency Plan for Refined Petroleum Product Imports which sets an obligatory level of stockholding at 31 days for industry. The emergency stock is called Country Wide Stock (CWS). In times of emergency, the government has a mandatory right to purchase and control all crude and oil product stocks held by the industry.

Cambodia

Cambodia has a stockholding obligation on industry to hold at least 30 days of domestic oil consumption. It is considered that the country will maintain this level of industry obligation into the near future.

Indonesia

The national oil company, Pertamina, holds 22 days of operational oil stocks based on domestic oil consumption. The National Energy Council (NEC) has a plan to strengthen the national stockholding system by holding public emergency stocks.

There is also an allocation system for supplying available oil to disrupted areas, called the Fuel Distribution System. Although the government has no specific legal authority to instruct the industry to implement the allocation mechanism, the government is able to request the industry to take the necessary measures to ensure domestic oil distribution as the industry needs to maintain its oil business licence.

Lao PDR

The oil industry is obliged to hold at least 15 days of oil imports. However, the government aims to establish public emergency stocks for up to 25 days of consumption.

Malaysia

As a net exporting country, the Malaysian government does not consider holding emergency oil stocks to be necessary. However, legislation clearly endows the prime minister with the authority to issue directions on the operations of Petronas in case of emergency – including full control over the company's stocks.

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Myanmar

The country held around 50 days of net imports in 2013. Most are commercial stocks, but it is reported that the government also holds around 18 days of oil stocks even though it is not clear that those public stocks are purely for emergency purposes. The government does not reveal its target for holding stocks of emergency oil; it is, however, expected that the country will hold around 70 days of net imports by 2015. The government plans to establish a target for a stockholding obligation on industry.

Philippines

Based on Presidential Executive Order No. 134 of October 2002, the government requires its oil refineries to maintain a minimum inventory level of 15 days, while oil importers are obliged to hold 7 days of domestic supply. It is considered that total stock levels, including operational stocks, must not be less than 30 days of daily domestic supply. The government envisages maintaining its existing obligation level.

In case of emergency, the government would activate its oil contingency plan in order to implement potential measures such as oil allocation.

Singapore

Power-generating companies in Singapore are obliged to hold 90 days of fuel oil stocks as backup fuels. However, there is no mandatory stockholding requirement for refineries or private oil companies operating in Singapore and obligatory crude oil stockpiling was abolished in 1983. Operational stocks in refineries are estimated at around 50 days.

Thailand

The Fuel Trade Act of 2000 places mandatory stockholding obligations on all refiners, retailers and importers in the private sector with operations greater than 100 kilotonnes (Kt) per year. Following amendment of the legislation in November 2013, the government imposes on refineries the obligation to hold 6% of their yearly sales of crude oil and oil products, and on retailers and importers to hold 6% of crude oil and 10% of oil products.

Their total levels must be at least 43 days of domestic consumption. Even before the amendment, the country's stockholding levels, including operational stocks, were equal to around 45 days of national demand. The Thai government has made a strong commitment to increase emergency oil stocks up to 90 days of consumption.

Viet Nam

In 2013, Viet Nam held 47 days of oil stocks based on consumption, which included 30 days of commercial stocks and 10 days of national products stocks. Based on the National Stockpile Master Plan approved by the prime minister in 2009, the country aims to hold at least 90 days of net imports (or around 60 days of consumption) by 2015. This would be achieved by increasing commercial stocks up to 40 days, by amplifying the level of operational stocks and by holding crude oil in the category of national stocks in addition to product stocks.

The General Directorate of Energy in the Ministry of Industry and Trade is a core body for oil emergency policy. In case of an oil supply disruption, the Committee on the State Management of Domestic Markets will be convened to make recommendations to the prime minister on possible emergency measures.

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Gas

Market features and key issues

Gas production

Southeast Asia's natural gas production has surged from 154 bcm in 2000 to an estimated 202 bcm in 2012, although it declined from 210 bcm in 2010. The region's proven reserves of natural gas are considered to stand at 7.5 trillion cubic metres (tcm).

By country, Indonesia produced 77 bcm of natural gas in 2012 (equal to 38% of the region's total), followed by Malaysia (56 bcm or 28%), Thailand (31 bcm or 16%), Brunei Darussalam (12.5 bcm or 6%), Myanmar (12 bcm or 6%) and Viet Nam (9.9 bcm or 5%).

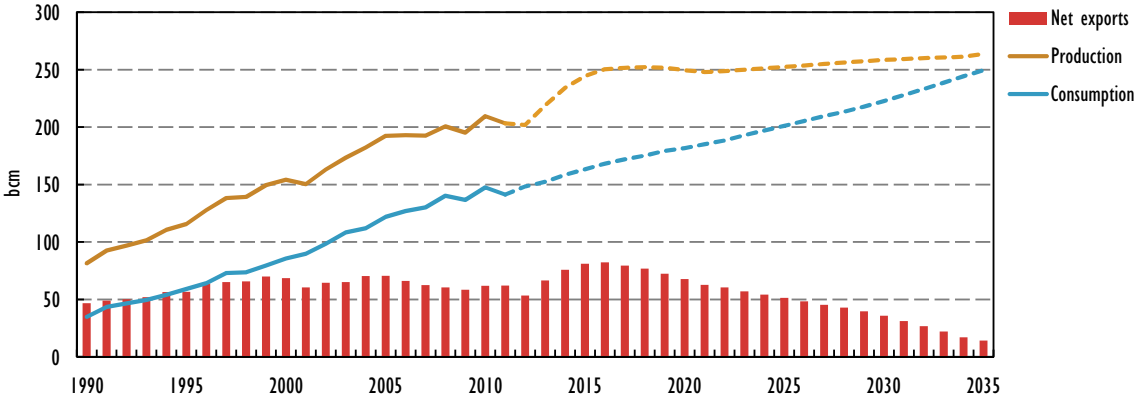
Natural gas production in the region is expected to reach 226 bcm in 2018 and 260 bcm in 2035. Indonesia and Myanmar, and to a lesser extent Malaysia, will be the main contributors to drive further increases in Southeast Asian gas production in the period to 2035. Thailand, however, sees its gas production drop by 75% in the same period.

Gas demand

Regional demand for natural gas has increased rapidly from 85 bcm in 2000 to around 149 bcm in 2012, the same level as Chinese natural gas demand in the same year. It is expected to reach 184 bcm in 2018 and 250 bcm in 2035.

At 21% of the primary energy mix, natural gas is the second most important energy source in the ASEAN region. The share of gas in the energy mix remains flat through to 2035, at just over 20%.

Figure 5.1.2 ASEAN regional gas balance



Source: IEA (2013), *Southeast Asia Energy Outlook 2013*, IEA, Paris.

By country, Thailand consumed the largest amount of natural gas in the region in 2012; this stood at 43 bcm or 29% of combined demand for the region. In the same year, two other large consumers were Indonesia with 39 bcm (26%) and Malaysia with 37 bcm (25%).

In the long term, Indonesia's consumption is estimated to more than double from around 40 bcm in 2012 to 81 bcm in 2035, driven by expanded use in fertiliser production, power generation and industry.

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Thailand's demand is also expected to rise from 43 bcm in 2012 to 65 bcm in 2035, with declining indigenous production meaning increased dependence on LNG imports. Natural gas dominates the power sector and is responsible for 68% of power generation; however, this share falls to 52% in 2035 as the country is expected to diversify the energy mix.

Malaysia, the third-largest energy consumer in the ASEAN region and a large net natural gas exporter, will increase its domestic demand for natural gas from 37 bcm in 2012 to 48 bcm in 2035.

Gas import dependency

Southeast Asia is a key exporter of LNG to global markets, and increasingly an LNG importer as well.

Combined net natural gas exports of the ASEAN countries (including trade among them) stood at 62 bcm in 2012, which mainly come from Indonesia, Malaysia, Myanmar and Brunei Darussalam. Despite increasing gas production, the combined net gas exports are expected to decrease to 14 bcm by 2035, even though the region remains a net exporter of natural gas. Volumes for exports will decline owing to growing domestic needs and because many of the key producing fields are mature and declining in output.

Brunei Darussalam was the first country in Southeast Asia to export LNG starting in 1972, and remains an important LNG exporter. Malaysia and Indonesia were also pioneers in LNG trade and remain among the top five important global exporters. However, Malaysia and Indonesia started importing LNG, as extra supply is needed to satisfy rising domestic needs (and overcome localised shortfalls) while respecting long-term export contracts.

In contrast, Thailand imported 11 bcm of natural gas in 2012 and Singapore imported 9.4 bcm in the same year. The majority of Thailand's imports come from Myanmar through pipelines. It is also expected that Viet Nam, the Philippines and Myanmar will join the net importers in the coming years.

LNG terminals

The region had 89 bcm per year of LNG liquefaction capacity in 2013, accounting for almost one-quarter of the world total. The facilities are located in Indonesia, Malaysia and Brunei Darussalam.

Indonesia's three operating LNG liquefaction plants (Bontang, Arun and Tangguh) have a combined capacity of 46 bcm per year. Two new liquefaction plants, Sengkang and Donggi-Senoro, are under construction on the island of Sulawesi. Additionally, there is a plan to expand the Tangguh plant together with the Abadi floating LNG (FLNG) project in the remote Arafura Sea. These projects will boost the country's combined liquefaction capacity to over 60 bcm.

Malaysia has a liquefaction capacity of around 33 bcm per year in its LNG terminal. An expansion plan will bring its total capacity to almost 38 bcm by 2015. Construction has also begun on the Kanowit FLNG terminal with a capacity of 1.6 bcm per year. The country also has plans to build a Rotan FLNG terminal and a Murphy FLNG terminal with a capacity of 2 bcm and 1 bcm respectively.

The Brunei LNG terminal started in 1972 and its liquefaction capacity is 9.8 bcm per year.

Fast-rising demand and limited interconnections between countries in Southeast Asia have prompted the installation of several LNG regasification terminals in recent years: Indonesia, Malaysia, Singapore and Thailand are now receiving LNG shipments. Their combined regasification capacity stood at 21 bcm per year at the end of 2013.

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Indonesia's first regasification terminal, a floating storage and regasification unit (FSRU) with a capacity of 4.1 bcm in West Java, started receiving deliveries in 2012. Two others were under construction in 2013 and there are plans to build several more in order to meet domestic gas demand.

In 2013, Malaysia became a simultaneous exporter and importer of LNG with the commissioning of the 5.2 bcm Lekas regasification terminal in Malacca. The facility is set to be supplied under long-term contracts signed with Qatargas and Gladstone LNG (Australia), while at least two other small regasification terminals are planned in Pengerang and Lahad Datu.

Singapore has a regasification terminal on Jurong Island with a regasification capacity of 4.8 bcm. Expansion plans will increase its capacity up to around 12 bcm per year.

With increasing domestic demand, Thailand started taking LNG shipments in 2011 following the opening of the Map Ta Phut regasification terminal with a regasification capacity of 6.8 bcm. It plans to double this capacity through expansion by 2016.

Viet Nam has plans to build three regasification terminals: Thi Vai terminal (1.4 bcm per year), Binh Thuan terminal (4.1 bcm) and Son My terminal (4.1 bcm).

The Philippines plans to build two regasification terminals, one by 2014 and the other by 2017. Once both facilities are operational, the country will have a combined regasification capacity of 3.3 bcm per year.

While the China-Myanmar Gas Pipeline was put into full operation with an annual transmission capacity of 12 bcm in October 2013, Myanmar also issued a tender in July 2013 to import increasing volumes of LNG.

Emergency policy

As most ASEAN countries are net exporters of natural gas, an emergency policy for natural gas disruption has not been highly prioritised in the region. There are no mandatory industry stocks or government stocks of natural gas in the region.

However, together with declining output, increasing domestic natural gas use has led countries to consider formulating an emergency response plan. While supporting projects to explore offshore natural gas fields, some countries have also started strengthening their regasification capacity and storage facilities by building up LNG receiving terminals (see above).

In one of the net natural gas importers in the region, Thailand, the government prepared the Mitigation Plan for Natural Gas Supply Disruption with relevant stakeholders, although there is no clear legal basis for emergency planning and managing crisis situations for natural gas. The plan aims to reduce the potential for shortages of electricity, liquefied petroleum gas (LPG) and liquefied carbon dioxide products during any disruption of natural gas supply from the Gulf of Thailand. The plan is designed to assist the upstream operators and a gas transmission system operator (TSO) during a gas supply disruption in maintaining fuel supply. Furthermore, the country's TSO, the PTT, has developed a colour alert system for categorising levels of disruption and for helping define actions for each level of disruption. These actions include surge production in unaffected domestic gas fields and fuel switching from natural gas to other alternative fuels in power plants.

In net producing countries, surge production is one of the most important measures available for tackling natural gas disruptions. However, the largest natural gas producing country, Indonesia, also issued Regulation No 03/2010 concerning natural gas allocation and usage for domestic needs. The regulation mainly focuses on normal time market obligation, but also sets the priority list for natural gas allocation.

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Chile

Key data

Table 5.2.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	24.6	9.0	7.6	13.3	12.8	11.3	7.7
Demand (kb/d)	145.5	239.6	272.3	322.9	333.9	356.2	397.3
Motor gasoline	32.5	56.1	49.7	65.1	60.6	62.6	-
Gas/diesel oil	46.5	82.2	102.3	142.2	155.3	167.5	-
Residual fuel oil	27.0	32.9	35.5	32.6	33.1	28.2	-
Others	39.6	68.5	84.8	82.9	84.9	97.9	-
Net imports (kb/d)	120.9	230.6	264.7	309.6	321.1	344.9	389.6
Import dependency (%)	83.1	96.2	97.2	95.9	96.2	96.8	98
Refining capacity (kb/d)	0.0	0.0	0.0	226.6	226.6	226.6	-
Oil in TPES (%)**	46	42	41	49	47	46	-

* Forecast.
** TPES data for 2012 are estimates.

Table 5.2.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	1 679	1 902	1 911	1 848	1 480	1 217	1 323
Demand (mcm/y)	1 360	6 196	8 086	5 296	5 703	5 047	6 033
Transformation	75	2 022	3 269	2 101	2 872	0	-
Industry	886	3 550	3 614	2 170	1 700	0	-
Residential	154	288	410	464	464	0	-
Others	245	336	793	561	667	0	-
Net imports (mcm/y)	- 319	4 294	6 175	3 448	4 223	3 830	4 710
Import dependency (%)	- 23.5	69.3	76.4	65.1	74.0	75.9	78
Natural gas in TPES (%)	8	21	24	14	14	13	-

* 2012 data are estimates.
** Forecast.

Note: This section was written by the IEA, based on information provided by the Government of Chile during the Emergency Response Assessment, public information, IEA statistics, press reports and reports from various energy analysts. It does not necessarily represent the official view of the Chilean government. All errors and omissions are solely the responsibility of the IEA.

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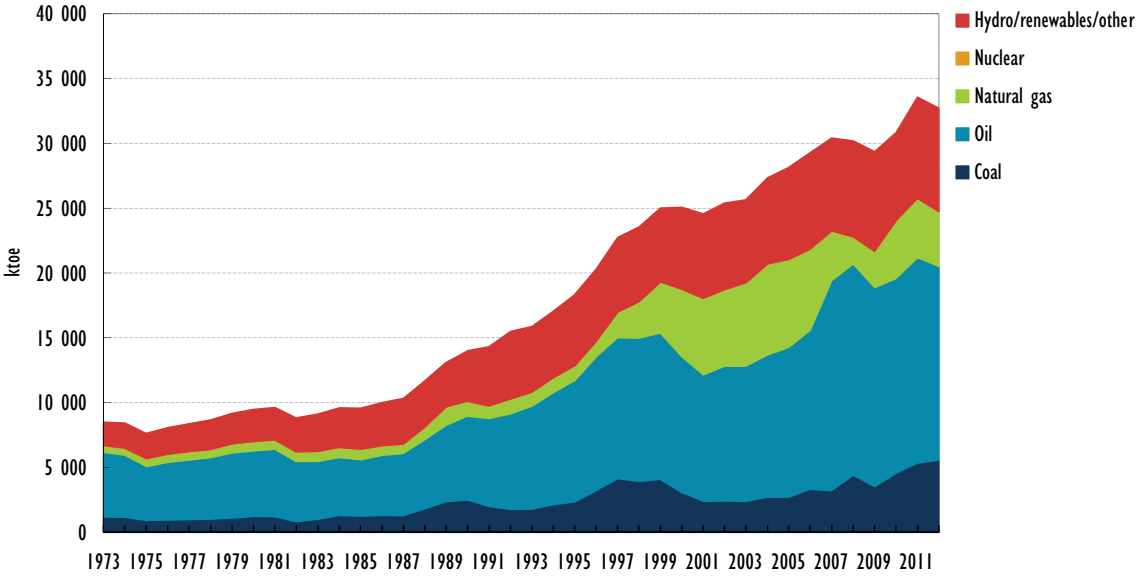
Figure 5.2.1 Total primary energy source (TPES) trend, 1973-2012



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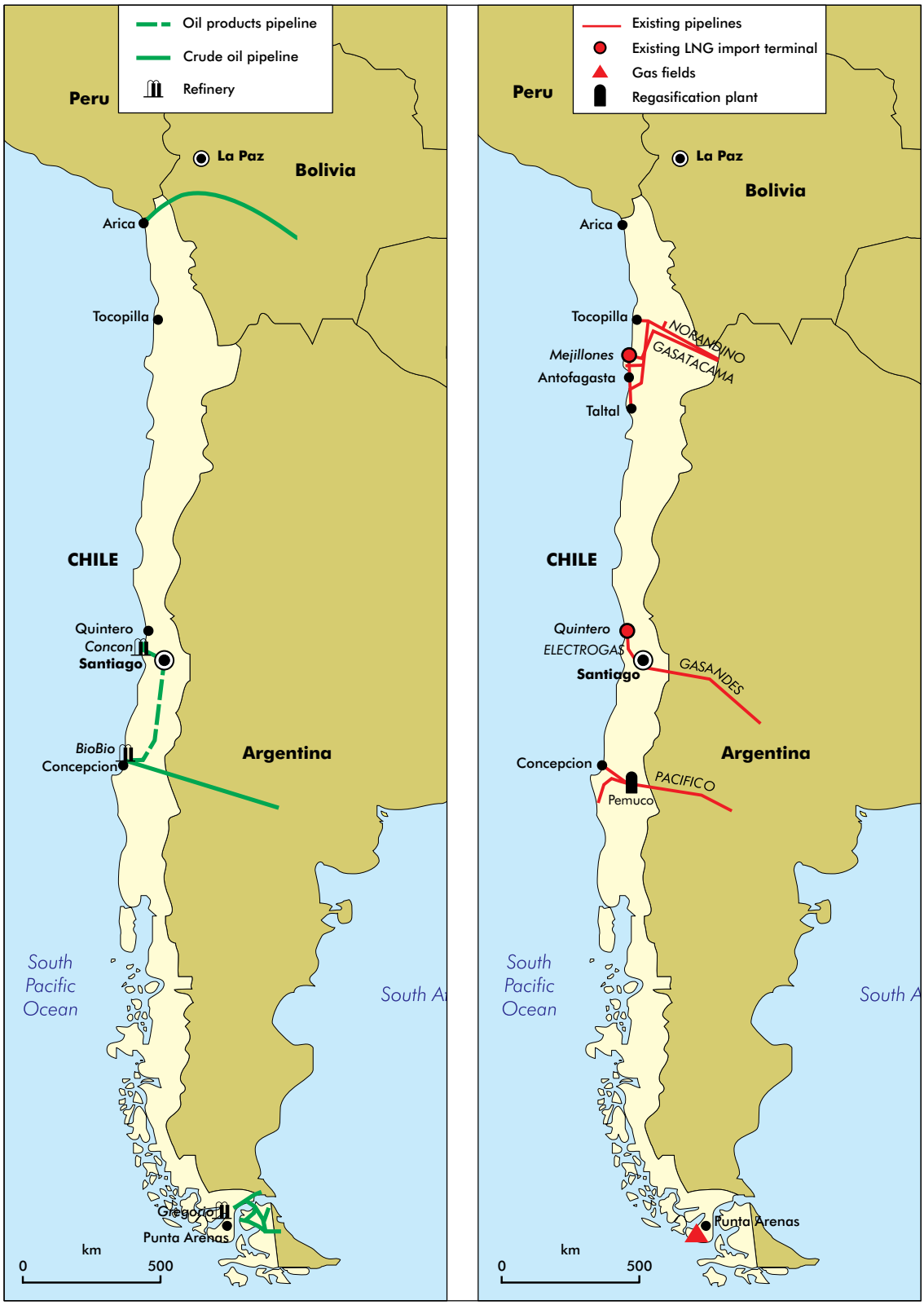
Map 5.2.1 Oil and gas infrastructure of Chile



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Country overview

Over the last decade, Chile has experienced several serious energy supply incidents including major droughts, a sustained gas supply cut from Argentina (since 2004), and a major earthquake in early 2010 which affected electricity networks and refineries and caused several black-outs.

Chile has a unique and sinuous geography – it runs 4 300 km from north to south and only 175 km from east to west – and its energy markets are regionally disjointed, particularly as the regional gas and electricity grids are not connected.

Chile's oil production accounted for only 3% of its total oil consumption in 2012. Production is located in the southernmost region of Magallanes y la Antártica Chilena, producing around 1 thousand barrels per day (kb/d) in 2012.

In 2012 Chile's oil demand was 333.5 kb/d. Gas/diesel oil accounts for 45% of product demand, and gasoline for 19% of demand. The demand for gasoil soared significantly as a result of the Argentine gas supply crisis, as gas-fired power plants switched to gasoil. Gasoil demand almost doubled between 2003 and 2008. In 2000, only 4% of gasoil demand was used for power generation, whereas it reached almost 30% in 2008. The construction of liquefied natural gas (LNG) terminals and the arrival of LNG supplies in Quintero in the centre of the country in mid-2009, and Mejillones in the north in 2010, attenuated the demand for gasoil which has stabilised since then.

Chile's refining portfolio is among the most sophisticated in the region. Its state-owned company (ENAP) operates three.apacity of 234 kb/d.

Chile does not currently hold strategic oil stocks but its oil industry participants have an obligation to hold stocks covering 25 days of their sales over the previous 6 months, or average imports over the same period if imports are for their own consumption. This requirement is currently not monitored or enforced.

With regards to natural gas, Chile has fragmented gas consumption centres. In the far north of the country gas is used predominantly to generate electricity for the mining industry and is supplied via the Mejillones LNG terminal. In the central and southern areas (including Santiago), gas is used both by industry and by residential customers and is primarily supplied by the Quintero LNG terminal. In the far south (Magallanes), gas supplies come from local production (1.2 bcm in 2012) and are the basis of the local energy mix (both for electricity generation and for heating purposes for the residential sector) as well as a key input in methanol production.

The bulk of Chile's 5.1 bcm gas demand in 2012 came from the power generation sector (51.9%). Industry and the petrochemical sector accounted for 36.4% each, and residential/commercial for the remaining 11.8% of Chile's gas demand.

Chile has no specific response system for handling a natural gas supply emergency. However, in response to the 2004 crisis resulting from the restriction of its natural gas supply from Argentina, the government, through the Superintendency of Electricity and Fuels (SEC), issued SEC Exempt Resolution No 754. This resolution established a priority order for gas supplies in case of a shortage. Once the crisis was over and the LNG terminals were built, the resolution was revoked.

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Oil

Market features and key issues

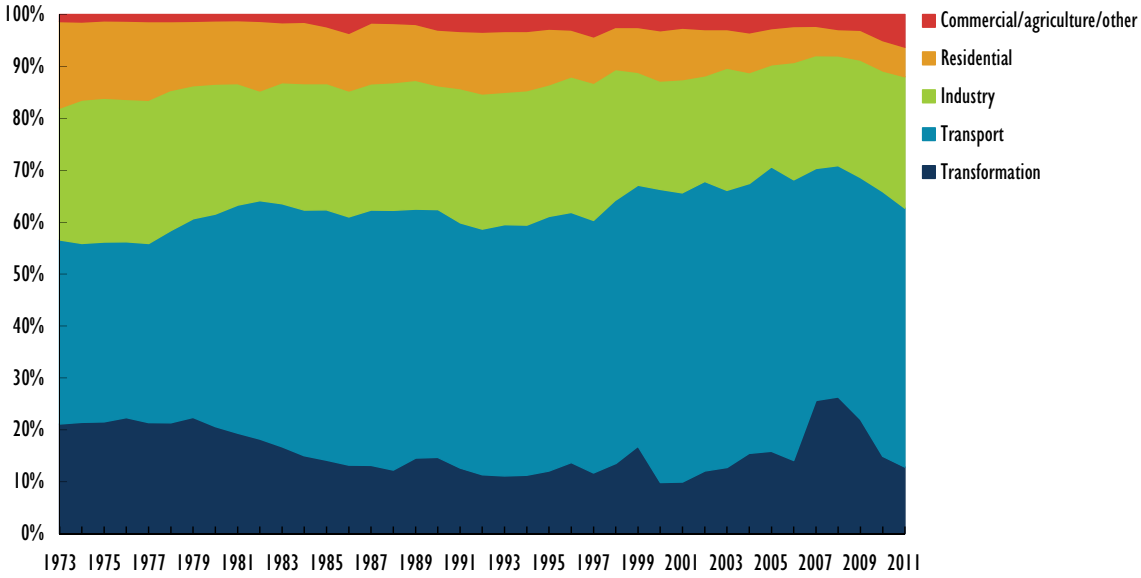
Domestic oil production

In 1990, Chile produced around 15 kb/d of crude oil, equivalent to some 14% of its oil demand. That percentage has been decreasing steadily, although recent efforts to encourage exploration activities through Special Oil Operation Contracts have started to reverse that trend somewhat. Nevertheless, production only accounted for 3% of total oil consumption in 2012. Production is located in the southernmost Magallanes region, standing at around 1 kb/d in 2012.

Oil demand

In 2012 Chile's oil demand stood at 333.5 kb/d. Gas/diesel oil accounts for 45% of product demand, and gasoline for 19% of demand. Demand for gasoil soared significantly as a result of the Argentine gas supply crisis, as gas-fired power plants switched to gasoil. Indeed, gasoil demand almost doubled between 2003 (before the gas disruption) and 2008 (complete disruption), growing from 87 kb/d to 169 kb/d. In 2000, only 4% of gasoil demand was used for power generation, while this figure reached almost 30% in 2008. The construction of LNG terminals and the arrival of LNG supplies in Quintero (centre) as of mid-2009 and in Mejillones (north) as of 2010 attenuated the demand for gasoil which has since stabilised.

Figure 5.2.2 Oil consumption by sector, 1973-2011



As is the case in most OECD member countries, the transport sector accounts for the majority of oil product demand in Chile. In 2012 it was 46%, followed by the industrial sector with 25%. More unusual in relation to Chile's OECD peers is the fact that in 2011, 19% of demand came from the power sector (in the form of demand for diesel).

Imports/exports and import dependency

With oil demand in Chile estimated at around 335.5 kb/d in 2012, Chile is a large net importer of both crude oil and oil products. About 95% of Chile's crude imports came

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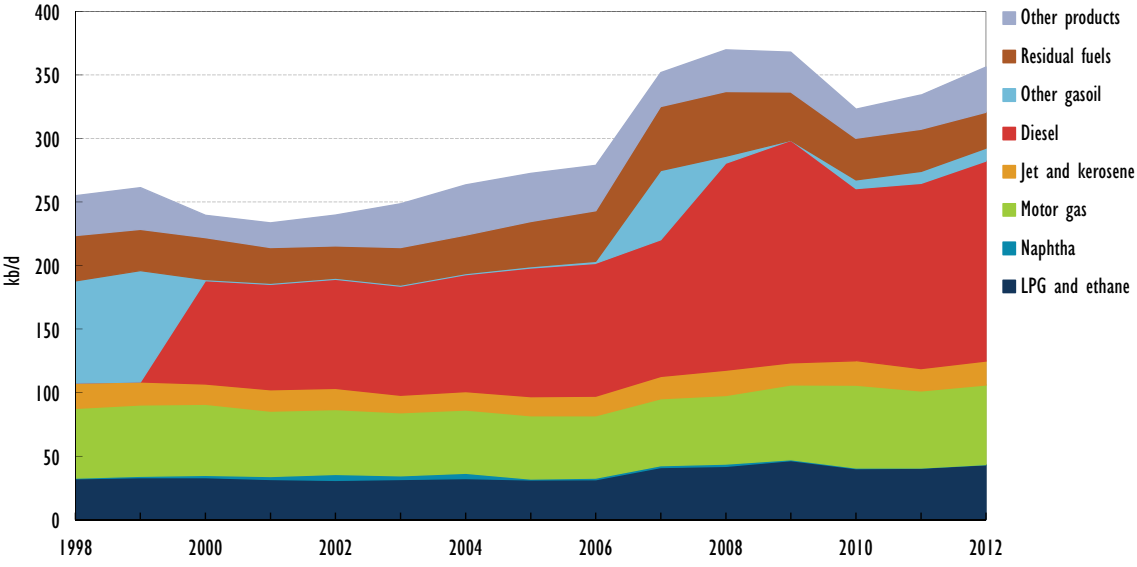
from South America in 2012. Domestic product supply is dominated by the Chilean National Oil Company (ENAP). Nevertheless, distillate imports by other companies made up a larger share of total supply in 2007 and 2008 to replace restricted natural gas supplies. Competitors with product supply from neighbouring Argentina have struggled in light of the stricter motor fuel standards in Chile and export restrictions in Argentina. As a result, most imported products are from OECD countries.

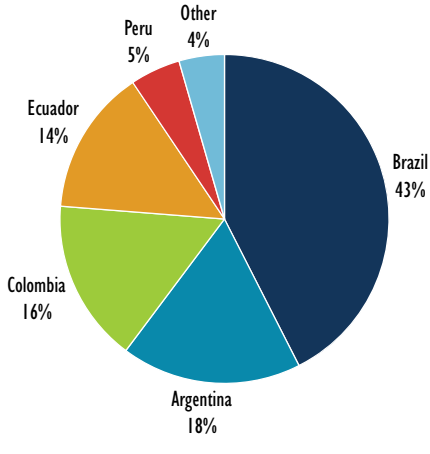
Figure 5.2.3 Oil demand by product, 1998-2012



Oil company operations

An established, competitive landscape keeps market shares in the retail sector fairly static, although two regional players, Petrobras (Brazil) and Terpel (Colombia), entered the Chilean market in 2008 by acquiring existing retail portfolios. With limited ability to compete on price (because companies rely on imports or buy from ENAP at import-parity prices), many competitors look to branding, location and non-fuel offerings to distinguish themselves and increase throughputs. There are over 1 660 retail sites in Chile.

Figure 5.2.4 Crude oil imports by origin 2012



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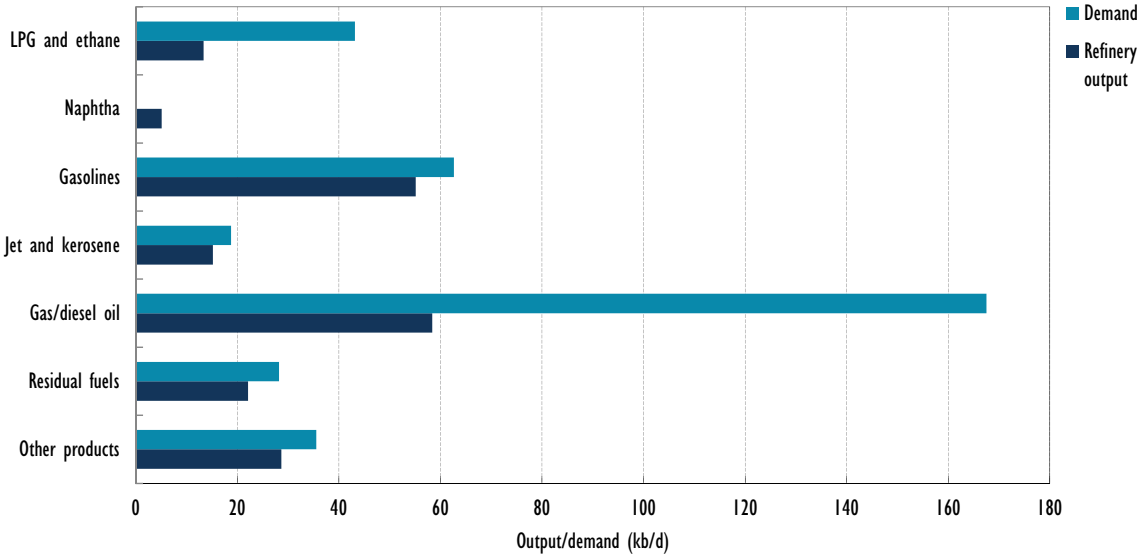
Refining

ENAP is engaged in the exploration, production, refining, and marketing of hydrocarbons and their derivatives. It is the only refiner in Chile, operating three refineries (Concón/Aconcagua, Concepción/Bío Bío, and Magallanes/Gregorio) with a total topping capacity of 234 kb/d.

ENAP's refining portfolio is among the most sophisticated in the region. The crude slate has moved towards intermediate and heavier crudes as the complexity of domestic refining has increased, allowing the company to take advantage of the more abundant, heavier, cheaper crudes available in South America.

The February 2010 earthquake severely damaged the Bío Bío Refinery, putting it out of operation for three to four months. The Concón refinery was out for six weeks.

Figure 5.2.5 Refining output vs. demand, 2012



Ports and pipelines

With its long coastline, Chile has 20 ports which are able to receive crude oil or oil product deliveries. Each has one or two docking terminals.

Transportation by pipeline is carried out exclusively by ENAP and Sonacol, a joint venture between Copec, ENAP, Petrobras (previously ExxonMobil), Abastible and ENEX (previously Shell). Sonacol is the main oil pipeline operator in Chile, owning and managing around 460 km of domestic oil product pipelines. Sonacol owns six pipelines and three terminals in the regions of Valparaíso, Bernardo O'Higgins and Metropolitana. Until recently, Sonacol was considered a "strategic" company, which meant that its workers were forbidden to go on strike, but this is no longer the case.

Sonacol's logistics assets are particularly important in the Santiago Metropolitan region, where it supplies more than 98% of all products. Products are received in Quintero Bay and loaded from ENAP's Aconcagua Refinery, and transported to Santiago by means of a multi-product pipeline.

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There is also a dedicated liquefied petroleum gas (LPG) pipeline to Santiago, which transported 7.5 million barrels (1.2 mcm) of LPG in 2008. Utilisation of the LPG pipeline is estimated at around 50%.

In addition, a dedicated jet-fuel pipeline supplies Santiago's Arturo Merino Benítez airport, which is operating at near full capacity.

A two-directional product pipeline from San Fernando to Santiago is connected to ENAP's Concepción-San Fernando pipeline, which transports the production of the Bío Bío Refinery up north.

Storage capacity

Chile's total storage capacity stands at 22 mb (3.65 mcm), of which 28.6% is crude storage and the rest is product storage.

The company with the most important storage capacity is ENAP. This storage capacity is significantly concentrated in its refineries: Aconcagua, Bío Bío and Gregorio. ENAP also operates fuel storage facilities in Maipú, San Fernando and Linares, all located in the central area. ENAP has 54.6% of the Chilean LPG storage, 57.8% of middle distillates and gasoline storage, and 77.2% of heavy fuel oil (HFO) storage.

However, other companies have their own storage facilities as well, such as Copec, ENEX, Petrobras, Terpel (which rents infrastructure to the Chilean chemical company OXIQUIM), JLC Combustibles and Hugo Najle.

One important feature in terms of security of supply is that storage capacity is not evenly distributed across the country, with two-thirds of the storage located in regions V and VIII[1] in the centre of the country where the two main refineries are located and where most of the demand is concentrated.

Decision-making structure

Chile has no specific national emergency strategy organisation (NESO), but does have an organisation for handling national emergencies caused by natural disasters or other events that affect the population. The National Emergency Office (Onemi), overseen by the Ministry of the Interior and Public Security, is responsible for co-ordinating public and private efforts to control emergencies, disasters and catastrophes and to co-ordinate all the actions and operations executed by the National Civil Protection Agency.

However, the SEC and the Chilean Nuclear Energy Commission (CCHEN), both of which are part of the Ministry of Energy, have their own emergency plans which are activated by events that alter the normal operation of the energy market.

In recent years the Chilean government has taken significant steps to improve its monitoring and communications in the event of an energy crisis. In the case of the oil market, the Ministry of Energy is using an informal market monitoring system for supply and demand, assessing the level of stocks for the country as a whole in terms of days of demand that could be covered. Three categories have been distinguished, namely "normal" (over 25 days), "alert" (between 15 and 25 days) and "serious" (less than 15 days).

In addition, in 2010, in the aftermath of the big earthquake, the ministry established co-ordination and communication protocols with the energy industry so as to have prompt information when events occur that significantly disrupt the energy supply. A 24-hour reporting system was implemented, ready to be used in case of an oil or power supply crisis and to enable key actors to make well-informed decisions, based on the

1. Chile is divided into 15 administrative regions.

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best available information. In 2011, the government undertook a study to revise and complement this communications system. As a result, these protocols with industry were updated and new protocols were established with the SEC and Onemi, now superseded by the National Civil Protection Agency. In general terms, these documents outline emergency procedures for ensuring efficient and streamlined delivery of information to facilitate the decision-making process in case events threaten the normal energy supply.

Stocks

Currently oil industry participants have an obligation to hold stocks. Producers (refineries) and importers of liquid, petroleum-based fuels are required to maintain an average stock of these products equal to 25 days of sales during the previous 6 months, or average imports over the same period, if imports are for own consumption.

Article 7 of Decree with Force of Law N° 1 of 1978 of the Ministry of Mining and Energy states: "Every producer or importer of liquid, petroleum-based fuels is required to maintain an average stock of each product which is equal to 25 days of average sales during the previous six months or average imports for the same period of time, if it is for own consumption".

However, this legal provision does not include a regulation to determine how such reserves are quantified, administered, or managed in emergency situations. Companies that maintain reserves administer them freely based on their operational needs. In situations of restriction of supply, distribution companies assist one another in maintaining supply to the country, in co-ordination with ENAP and the energy authorities.

To monitor compliance with this requirement, the SEC has ordered producers and importers of liquid, petroleum-based fuels to submit a monthly spreadsheet detailing sales for the period, daily stocks of liquid petroleum-based fuels and crude oil in their facilities, and imports of liquid petroleum-based fuels during the same period. In addition, the National Commission of Energy (CNE) now requires major distributers (including producers and importers) of petroleum-based fuels to submit daily stock reports for key fuels in their facilities on a weekly basis.

Because the law is unclear about who is strictly responsible for holding these stocks, and there is no clear methodology for how to count them, there is no enforcement of compliance with this obligation, and no penalties have ever been levied for non-compliance. There is also no mechanism or procedure in place for using these reserves in case of an emergency.

Other measures

Demand restraint

Until 2011, Chile did not have a clearly established demand restraint policy for liquid fuels. However, that year the Ministry of Energy elaborated a plan that included six demand restraint measures. These measures mainly targeted the transport sector,, although not exclusively, since it has the biggest share of consumption.

During 2012, the government undertook a study to revise these measures to assess if there were legal or administrative restrictions for their implementation. The main conclusion of the study was that to establish an oil demand restraint plan, a specific law is required.

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Fuel switching

Fuel switching from oil to other fuels is very limited. On the contrary, most fuel switching in Chile has involved switching from other fuels into oil. For example, switching to diesel was how the operators of many gas-fired power plants adapted to an acute gas supply disruption following the curtailment of gas supplies from Argentina. More regularly, oil consumption often spikes during periods of drought as oil-based thermal generation is used to replace hydropower generation.

Other

Chile's motor fuel specifications for gasoline – 50 parts per million (ppm) of sulphur lowered to 15 ppm in the Metropolitan Region in September 2011, and in the other regions in 2012 – and diesel – as of September 2013, 50 ppm sulphur and 50 cetane – are stricter than those of its neighbouring countries. Therefore, product imports are sourced from OECD countries, which are located further away from Chile. In particular, the diesel specifications stipulated by Chilean regulations mean that diesel can only be supplied by a small number of refineries located in Chile, Japan, the Republic of Korea and the United States. There is little potential for neighbouring countries to provide an alternative source of supply, as they produce insufficient diesel even to meet their own internal demand.

In September 2013, a new regulation was implemented that requires all diesel used for transportation purposes to comply with the Euro V specification (15 pppm sulphur and 50 cetane.

In situations of fuel supply shortage, these restrictions can exacerbate a disruption of supply. This is notably the case for diesel oil, where imports in some years have accounted for more than 60% of domestic consumption, potentially posing a short-term supply risk because of the lack of available fuel in the international market to meet Chile's standards.

This occurred in 2008, following the disruption of gas supply from Argentina. The domestic impact of the loss of gas supplies at this time was exacerbated by a drought that boosted demand for thermal electricity generation, and by a tight global market for high-quality diesel. Diesel oil constituted an essential input as a backup fuel for replacing gas in the generation of the country's electricity. Diesel consumption had already doubled since 2004 as a result of cuts in imported natural gas and the dry hydrology of the country (affecting hydroelectricity generation) during 2007 and 2008. At the same time, the transport sector lacked substitute fuels for diesel.

In response to these imperatives, the government lowered the specifications for B-grade diesel oil in 2008 for a one-year period, in order to expand Chile's options in terms of purchasing from foreign refineries.

Gas

Market features and key issues

Gas production and reserves

Chile has fragmented gas consumption centres. In the far north of the country gas is used predominantly to generate electricity for the mining industry and is supplied via the Mejillones LNG terminal. In the central and southern area (including Santiago), gas is used both by industry and by residential customers and is primarily supplied by the Quintero LNG terminal. In the far south (Magallanes y la Antártica Chilena), gas supplies

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come from local production (1.2 bcm in 2012) and are the basis of the local energy mix (both for electricity generation and heating purposes for the residential sector) as well as a key input in methanol production.

Gas demand

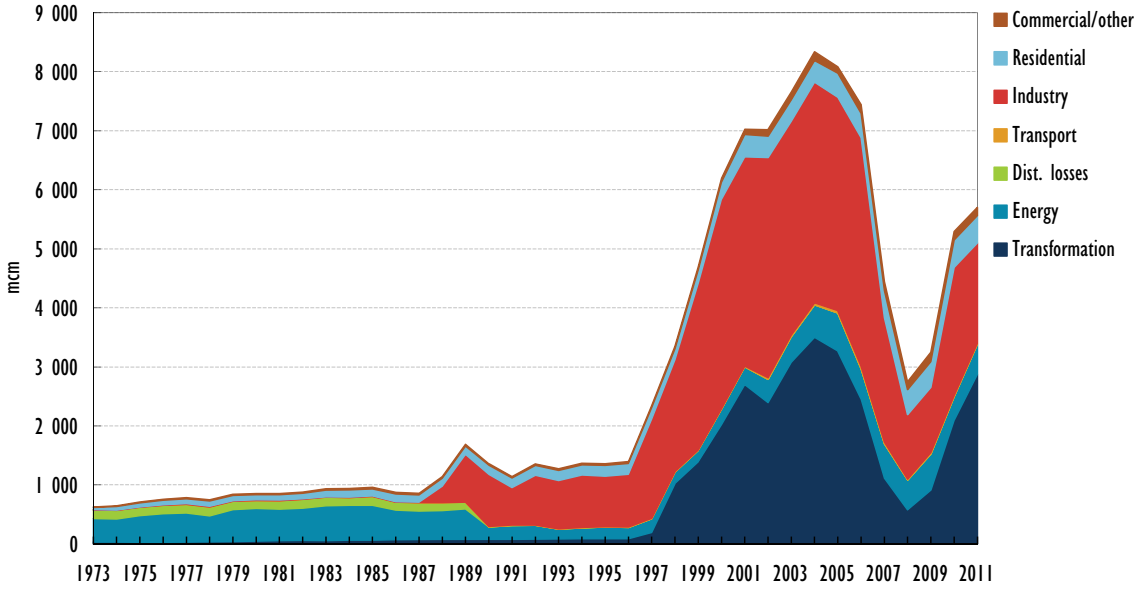
An event of the utmost significance for the Chilean gas market was the abrupt curtailment of piped gas supplies from Argentina from 2004. As a result, consumption plummeted, from a peak of 8.4 bcm in 2005 to just 2.8 bcm in 2008. Demand recovered in 2009 with the advent of the new Quintero LNG terminal, reaching 3.3 bcm. This was followed by the opening of the Mejillones LNG terminal, and the associated growth in volumes at the Quintero terminal. Natural gas demand is estimated to have increased considerably, reaching 5.02 bcm in 2012.

Chile is an attractive market for LNG, as the country is short of gas and its demand is counter-seasonal to markets in the northern hemisphere. The LNG terminals are now able to replace part of the Argentinean gas that was used in the northern and central regions of the country. The methanol plant in the Magallanes region receives very little imported gas and relies instead on limited domestic production.

The bulk of gas demand (51.9%) in 2012 came from the power generation sector. Industry and the petrochemical sector accounted for 36.4% each, and residential/commercial for the remaining 11.8% of Chile's gas demand.

There is, however, no transparent or liquid wholesale spot market for natural gas in Chile.

Figure 5.2.6 Natural gas consumption by sector 1973-2011



Gas import dependency

The northern and central regions of Chile are completely dependent on imports to meet their gas demand. Production in the southernmost Magallanes region remains insufficient to meet the needs of the local methanol plant (Methanex).

Argentina was the sole supplier of gas to Chile from 1996 to 2008. However, the recent construction of Chile's two LNG terminals has greatly diversified Chile's supply options.

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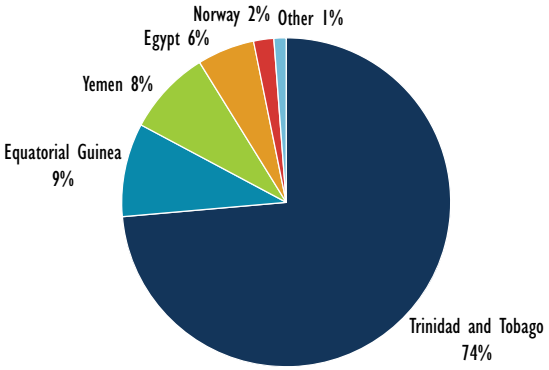
Figure 5.2.7 Natural gas imports by source in 2012



Gas company operations

The Association of Natural Gas Distributors (AGN), represents the four natural gas distribution companies operating in central and southern Chile, namely Metrogas, GasValpo, GasSur, Intergas and Gasco Magallanes. AGN members have no stake in the Mejillones LNG plant, and do not distribute gas in the far north. In total, the gas distribution market supplies around 560 000 clients in the Metropolitan, V, VI, VIII and XII regions of Chile.

Innergy is the main merchant company for the Concepción area (some 400 km south of Santiago). In 2012, Innergy received on average 125 000 m^3/d of gas from Argentina to meet residential demand, but there are large seasonal swings in the delivery pattern. This gas comes through Gasoducto del Pacífico.

To meet its Bío Bío Refinery demand, ENAP developed a "virtual pipeline", through which LNG supplies are transported by truck from Quintero to Pemuco, a medium-size regasification plant in the Concepción area. Pemuco has the capacity to process 600 mcm/d of gas. Currently, ENAP is injecting approximately 340 mcm/d exclusively to Bío Bío. Innergy has approached ENAP to discuss the option of injecting additional gas for residential and other industrial customers. This LNG trucking option, although expensive, could provide a higher level of energy security.

There are few LPG distributors in Chile (notably Gasmar, one of the key players and importers). LPG storage is generally estimated to cover around 15 days of peak winter demand at any one time. In the north where weather conditions are milder – and therefore consumption lower – storage levels are equivalent to around five days of peak demand.

Gas supply infrastructure

Ports and pipelines

Chile has two LNG terminals, located at the ports of Quintero (in the central region) and Mejillones (in the far north). These terminals provide a strong degree of energy security given their flexibility to contract supplies from different sources.

Quintero (2.9 bcm/year) has a regasification terminal in Quintero Bay which was completed in July 2009, and which feeds the central gas market of the Santiago Metropolitan and Valparaíso by pipeline. Quintero was the first land-based regasification facility in the southern hemisphere.

The plant has three vaporisers (5 mcm/d each), but only two are used at any one time, so as to have one spare as a backup for major emergencies. The maximum draw-down rate for Quintero is 10 mcm/d. Quintero has an average send-out capacity of 8 mcm/d, with a

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historical peak of 10 mcm/d, which is reached during dry seasons when there is not enough hydro capacity and all gas power units of the central area are working to full capacity.

Mejillones (748.3 mcm/year) is located in the far north of the country, and initially was a 50/50 joint venture between the Chilean state copper miner Codelco and GDF Suez. As of the end of 2013, Codelco owns 37% and GDF Suez owns 63%. Mejillones started as a floating offshore storage terminal, but an onshore storage tank is currently under construction; it is expected to be in regular operation by 2014. The LNG onshore regasification terminal began commercial operations in May 2010 and theoretically has the capacity to send out 5.5 mcm of gas per day, enough to produce 1 100 megawatts (MW) of electricity.

Chile has close to 20 ports that can be used for delivering oil products to the market, but only three are actually equipped to receive LPG imports. As a result, LPG supplies (particularly in some of the more isolated regions in the southern regions of the country) are dependent on road deliveries.

Since the late 1990s, a series of six pipelines have been built linking Chile to Argentina. The flow through these pipelines was restricted as of 2004, and then almost completely cut during the winter of 2007-08, rendering the pipeline infrastructure relatively useless.

The Quintero LNG terminal now supplies gas to the Santiago pipeline network through the reversible Electrogas pipeline, which links the terminal with the power stations in Quillota and then with the GasAndes Pipeline. Electrogas maintains some 850 000 m^3 of gas in its pipes for distribution companies.

Storage

Chile has no stand-alone gas storage sites. The geology and seismic nature of the country makes gas storage problematic. The fact that gas storage is considerably more costly than oil storage is an additional impediment to developing gas storage sites.

However, storage capacity does exist at the country's two LNG terminals: Quintero has the equivalent of 334 000 m^3 and Mejillones has 160 000 m^3. However, there is no obligation for the LNG terminal operators to hold a minimum amount of stocks, despite the fact that weather conditions can disrupt supplies, particularly in Quintero.

Emergency policy

Chile has no specific response system for handling a natural gas supply emergency. However, in response to the 2004 crisis resulting from the restriction of the natural gas supply from Argentina, the government issued SEC Exempt Resolution No 754. This resolution established a priority order for gas supplies in case of a shortage. Once the crisis was over and the LNG terminals were built, the resolution was revoked.

In addition, Decree 67 of 2004 issued by the Ministry of Economy, Promotion and Reconstruction, which approved the Regulation on the Network Gas Service, contains an article (Article 63) which establishes the following obligation for gas distribution companies: "supply security must be guaranteed by concessionaires in order to satisfy the demands of clients or consumers with firm contracts, projected for the next two years." Towards that end, the companies must have supply and gas transportation contracts and/or their own production and/or storage facilities in order to meet at least the maximum daily consumption projected for its services for the following two years, and at least the total firm consumption projected for the next two years.

Article 66 of the same Decree indicates that a gas distribution company must inform the SEC of any emergency within 24 hours of learning of the event.

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The People's Republic of China

Key data

Table 5.3.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	2 774	3 262	3 639	4 124	4 134	4 125	4 409
Demand (kb/d)	2 333	4 642	6 748	9 085	9 471	9 840	11 959
Net imports (kb/d)	441	1 380	3 109	4 961	5 337	5 715	7 550
Import dependency (%)	19	30	46	55	56	58	63
Refining capacity (kb/d)	N/A***	N/A***	N/A***	12 587	13 020	13 410	17 710
Oil in TPES (%)**	14	19	18	17	16	-	-

* Forecast.
** TPES data for 2012 are estimates.
*** Comparable data are not available.

Table 5.3.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	15 300	27 200	49 320	94 848	103 100	109 364	172 728
Demand (mcm/y)	15 990	24 503	46 764	105 526	130 950	142 000	295 000
Net imports (mcm/y)	690	2 697	2 556	10 678	27 850	32 636	-
Import dependency (%)	4	11	5	10	21	23	-
Natural gas in TPES (%)	1	2	2	4	4	-	-

* 2012 data are estimates.
** Forecast.

Note: This section on China was written by the IEA, based on public information, IEA statistics, press reports and reports from various energy analysts, and does not represent the official view of the Chinese government. All errors and omissions are solely the responsibility of the IEA.

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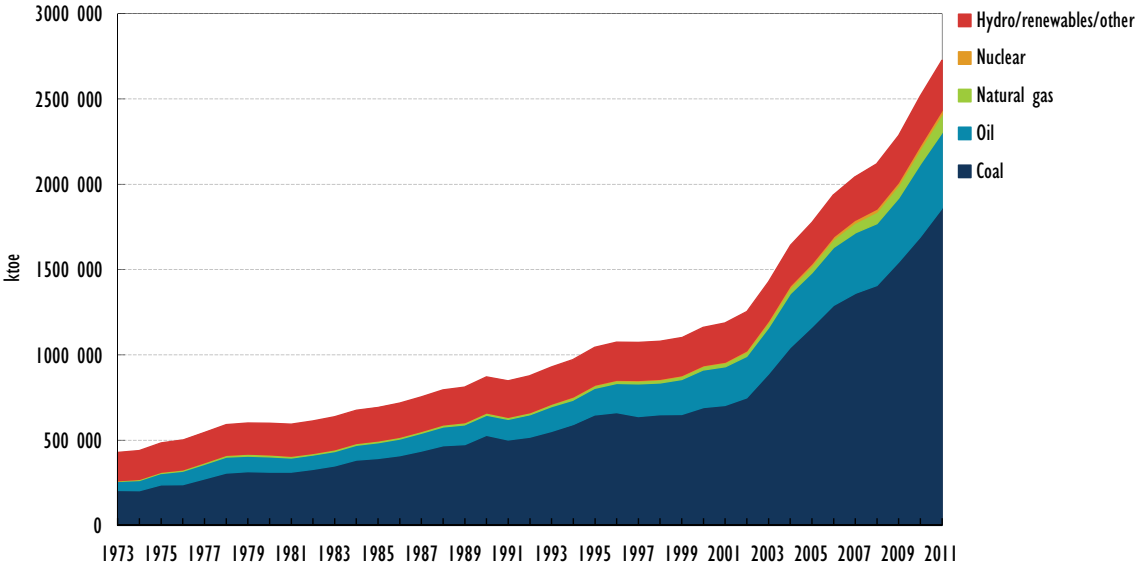
Figure 5.3.1 Total primary energy source (TPES) trend, 1973-2012



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Map 5.3.1 Oil infrastructure of China

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Map 5.3.2 Gas infrastructure of China

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Country overview

Although coal is the dominant energy source in China, accounting for some 68% of the country's total primary energy supply (TPES) in 2011, oil and gas are also essential energy sources. Despite strong growth in the consumption of oil, its share of TPES fell from 21% in 2002 to 16% in 2011, as coal use rose even faster to meet the burgeoning demand for electricity. A strong policy push boosted natural gas supplies, particularly to residential customers, so that the share of natural gas doubled from 2% in 2000 to 4% in 2011.

China is an important oil and natural gas-producing country. In 2012, China's crude oil production exceeded 4.1 million barrels per day (mb/d). However, with strong and sustained economic growth, its demand for oil has also increased, from 4.6 mb/d in 2000 to some 9.8 mb/d in 2012. Overall demand is expected to continue along this increasing trend. China's primary oil demand will rise to around 12 mb/d in 2018. Although China is the world's fourth-largest oil producer, the country has been a net oil importer since 1993. In 2012, China imported over 5.4 mb/d of crude oil, accounting for about 55% of its total demand. Around 50% of its total crude oil imports came from the countries of the Middle East.

To prevent a potential shock to the economy caused by an oil supply disruption, the Chinese government has been steadily building an oil stock reserve system. China has completed four stockpiling facilities with a capacity of around 103 mb in the first phase of its Strategic Petroleum Reserve (SPR) plan, and has begun construction of its second phase. Together with the completion of the third phase, the country expects to boost its SPR capacity to approximately 500 million barrels by 2020. Stockholding obligations for industry may be considered, but were not a formal part of the emergency response system as of 2013. Legislation to that effect is still in preparation.

Domestic natural gas production surged from about 27 billion cubic metres (bcm) in 2000 to 109 bcm in 2012, or a compound average growth of 12% annually. In 2012, domestic supplies met more than 70% of domestic consumption.

As the use of natural gas grew, China began importing liquefied natural gas (LNG) in 2006 and became a net importer in 2007. In 2012, gas demand reached around 149 bcm, while it is forecast to increase to 295 bcm by 2018. China imports natural gas both in the form of LNG and through gas pipelines. In 2012, China imported natural gas from Turkmenistan (19.3 bcm or 49% of its total imports) through pipelines, and LNG from Qatar (6.9 bcm or 17%), Australia (4.8 bcm or 12%) and Indonesia (3.3 bcm or 8%).

The key elements of China's approach to gas security are to further promote its domestic production from both conventional and unconventional resources, to expand its reserves, to construct gas storage facilities and to accelerate construction of LNG terminals and interregional gas pipelines in order to strengthen the supply of gas imports. Although China does not have government gas stocks or mandatory industry stocks, the government promotes the expansion of natural gas storage facilities to cope with seasonal demand fluctuations.

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Oil

Market features and key issues

Domestic oil production

In 2012, China's crude oil production increased to 4.13 mb/d (206 million tonnes [Mt]), from 4 mb/d (200 Mt) in 2011.

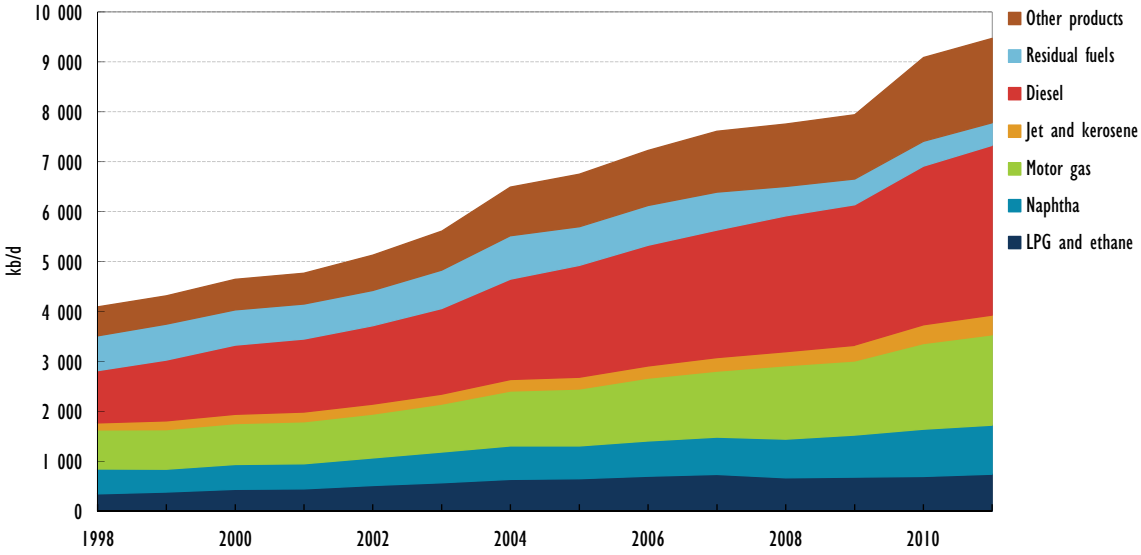
Exploration in the northwest and offshore has contributed to the growth of China's remaining proven oil reserves since 2000. China's offshore oil production rapidly increased, while oil production in the northeast has gradually decreased each year.

To secure oil supplies, in recent years the main state-owned oil companies have enhanced investment in domestic and foreign oil exploration. Total crude oil production is expected to continue increasing at least to 2018, reaching 4.4 mb/d.

Oil demand

China's total oil demand in 2012 averaged around 9.84 mb/d. It has been rising rapidly from 4.6 mb/d in 2000, increasing by a compound average growth rate of 6.5%. Overall demand is expected to continue increasing gradually along this trend. The *Medium-Term Oil Market Report 2013* sees China's primary oil demand rising to around 12 mb/d by 2018.

Figure 5.3.2 Oil consumption by product 1998-2011



The transportation sector accounted for over 45% of oil consumption in 2011, with motor gasoline, gas/diesel oil being the main transportation fuels. It is expected that demand for those oil products will be the main component of the total oil demand of the country. The industry sector accounted for 24% of total consumption and the residential sector for 7%.

By product, demand for oil products increased from 2002 to 2011, with the exception of residual fuels. Demand for diesel and gasoline doubled during the last decade, while demand for naphtha and jet/kerosene also increased significantly by 98% and 78% for the same time period.

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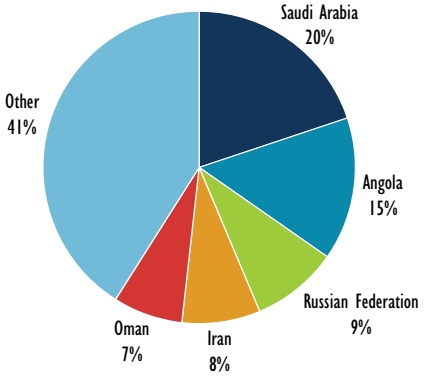
Imports/exports and import dependency

With sustained demand growth, China's oil imports have also continued to increase. The country has been a net oil importer since 1993 and a net crude oil importer since 1996. According to data from China Oil, Gas and Petrochemicals (China OGP), in 2012, China imported some 5.47 mb/d of crude oil, accounting for around 55% of total demand.

Figure 5.3.3 Crude oil imports by origin, 2012



According to China OGP, China is highly dependent on the Middle East for its imports of crude oil, which accounted for around half of total crude imports in 2012, followed by Africa (24%) and the Former Soviet Union (13%). By country, Saudi Arabia (20% of the total) was the biggest import source of crude oil in 2012, followed by Angola (15%), the Russian Federation (9%), Iran (8%) and Oman (7%).

In addition, China exported around 0.49 mb/d of oil products (about 24 million tonnes [Mt]) in 2012, while the country imported around 0.8 mb/d of oil products (about 40 Mt).

Oil company operations

The Chinese oil market is dominated by four major national oil companies (NOCs): China National Petroleum Corporation (CNPC), China Petrochemical Corporation (Sinopec), China National Offshore Oil Corporation (CNOOC) and China National Chemicals Import and Export Corporation (Sinochem).

CNPC, established in 1988, is a comprehensive energy company that has integrated a broad range of upstream and downstream oil and gas businesses. The company also manages technical services for oil and gas development projects, including logistics and manufacturing. In 2012, CNPC's domestic crude oil production was about 2.2 mb/d (110 Mt/year) and its share in overseas production was 0.8 mb/d (42 Mt/year). CNPC produced 79.9 bcm of natural gas domestically and its share in overseas production reached 13.7 bcm. PetroChina is the internationally listed subsidiary of CNPC.

Sinopec was established in the 1980s from the assets of the former Ministry of Petroleum Industry. The company has an integrated system covering oil production, refining and sales. The petrochemical business is also a core activity, including maintenance of a comprehensive retail network. Sinopec's subsidiary, the China Petroleum and Chemical Corporation, went through an initial public offering by listing the stocks on global stock exchange markets. In 2012, Sinopec produced 0.9 mb/d of crude oil and some 17 billion cubic metres (bcm) of natural gas.

CNOOC is the third-largest oil company in China and was established to exploit China's offshore oil and gas resources. In 2012, CNOOC crude oil production stood at around 0.7 mb/d; that year, it also produced 10 bcm of natural gas.

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Sinochem is a large NOC that produces oil, fertiliser and chemical products, and is also involved in the trade and sale of these products. Its activity extends to overseas oil exploration, production and refining, including oil storage services. Its oil equivalent production stood at around 64 kb/d in 2012.

Oil supply infrastructure

Refining

China's oil refining industry has vigorously promoted large-scale reorganisation and integration of its refineries. China's crude distillation capacity increased from about 7 mb/d in 2005 to around 12 mb/d in 2010, and then to 13.4 mb/d in 2012.

China's refining industry is commonly divided into two groups: independent refiners and major refiners. There are about 80 major refineries belonging to CNPC, Sinopec, CNOOC, Shaanxi Yanchang Petroleum Group (SYPG) and China North Industries Group Corporation (CNGC). The total capacity of these major refiners in 2012 was 10.1 mb/d.

Large refineries are mainly located in three areas, namely in the Yangtze River Delta, the Pearl River Delta and the Bohai Rim.

In line with increasing refinery capacity, refinery throughputs have also kept increasing steadily. Chinese refinery crude runs reached a record high of 10.2 mb/d in December 2012. While refinery processing has been more modest in 2013, averaging 9.5 mb/d in the first ten months of 2013, this is still a considerable increase compared with 2.7 mb/d in 2005 and 8.5 mb/d in 2010 (and 9.3 mb/d for 2012 on average). The product output of gasoline in 2012 was around 1.8 mb/d, while for diesel it was 3.3 mb/d and kerosene reached around 0.5 mb/d.

Ports and pipelines

China's oil pipelines have been rapidly expanding as well. The country is estimated to have over 22 000 km of crude oil pipelines. Pipelines run mainly in the northeast, the northwest and the coastal areas. It is estimated that around 70% of China's domestically produced crude oil is transported through pipelines. In the near future, it also plans to build around 10 000 km of crude oil pipelines.

The China-Russia spur of the Eastern Siberia-Pacific Ocean oil pipeline (ESPO) with a capacity of 300 kb/d or 15 million tonnes (Mt/year), became operational in 2010. The second phase of the Kazakhstan-China oil pipeline is planned for completion by the end of 2013. This will boost China's total transport capacity to 400 kb/d or 20 Mt/year. The China-Myanmar oil pipeline (around 440 kb/d or 22 Mt/year) is also planned to become operational in 2014.

Regional oil product pipelines have also been constructed, mainly in the northwest, the southwest and in the Pearl River Delta. China has built around 20 000 km of refined product pipelines, which are projected to transport around 20% of total oil products.

As China has a long coastline, it has around 60 operating oil ports. According to China OGP, around 60% of China's crude and oil product imports arrived at five main port areas in 2011: Ningbo, Quingdao, Hangzou, Dalian and Zhanjiang.

Storage capacity

China has been committed to the construction of its Strategic Petroleum Reserve (SPR). The government plans to complete 500 mb (or around 80 mcm) of SPR capacity in three progressive phases by 2020.

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The first phase (SPR-I) includes four storage facilities with a capacity of 103 mb (or 16.4 mcm). These were completed and fully filled with crude oil by 2010.

In the second phase (SPR-II), according to the *Yearbook of China National Petroleum Corporation 2011,* China plans to build a total additional capacity of 207 mb (or 33 mcm) in eight locations. However, as the government treats the SPR as a state secret, information on capacity increases and stock levels remains elusive. According to public information, it is likely that the second phase will include more than 207 mb of storage capacity. Although completion of the second phase was forecast for the end of 2013, it appears that it has been delayed until 2015.

The third phase (SPT-III) provides for the building of the remaining capacity. Available estimates suggest that this phase will range from 150 mb to some 200 mb/d of additional capacity, thus boosting total SPR capacity to 500 mb by 2020. Construction of SPR sites in SPT-III has not been started.

While building the SPR, the government has also encouraged domestic oil companies to increase their commercial reserves in order to meet fast-growing domestic oil demand.

As China is projected to see a large growth in its global refining capacity, potentially adding over 4 mb/d by 2018, its new refineries will require significant storage capacity to hold operating stocks of both crude and refined products.

However, the total commercial inventory level is still unclear, as there is much ambiguity surrounding commercial storage expansion, perhaps in part because of an unclear distinction between SPR sites and commercial storage.

Decision-making structure

The State Council, comprised of the premier, vice-premiers, state councillors and ministers, is the main decision maker and has the authority to order releases from the SPR. The National Development and Reform Commission (NDRC), the National Energy Administration (NEA) and the Ministry of Finance co-operate on the implementation of orders from the State Council. The National Oil Reserve Center (NORC) is a core body and responsible for SPR construction and oil procurement. The NORC is overseen by the National Oil Reserve Office of the NEA. Major NOCs, such as CNPC, Sinopec and Sinochem, serve as contractors for operations of strategic oil reserves.

While building the SPR, China is considering placing a minimum stockholding obligation on industry, thus creating a comprehensive national reserve system – the National Petroleum Reserve. This is expected to be composed of government stocks and obligatory industry stocks, and will include both crude oil and products. The NEA is reported to be considering public subsidies to support industry's stockholding requirements.

The legislation governing the National Petroleum Reserve is still in draft form but is considered to stipulate the detailed rules and regulations.

Stocks

Stockholding structure

In order to prevent and mitigate the damage caused by oil supply disruptions, since 2001 China has been steadily moving forward with the building of an oil stock reserve system. In 2001, China's Tenth Five-Year Plan (2001-2005) called for the establishment of a national strategic oil stockholding system to improve China's energy security. In 2003, the Chinese government announced the construction of four stockpiling facilities (NORC bases) in the first phase of its SPR plan. Having completed the first phase of its SPR plan

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in the coastal areas, it has begun construction of its second phase, which is considered to be made up of eight storage facilities, not only in the coastal areas but also in the northwest and the centre of the country. . Although crude oil is considered for storage under these SPR plans, China also reportedly has a plan to set up a refined oil reserve.

Under the SPR-I, four storage facilities were built between 2004 and 2008: Zhenhai, Zhoushan, Huangdao and Dalian, which have a total capacity of 16.4 mcm (103.2 mb). According to the NEA's Report on China's Energy Development for 2011, these bases are located near refining centres on the east coast and have been filled with crude oil since 2010.

SPR-II may include more than eight storage facilities with more storage capacity. Among them, the Dushanzi and Lanzhou sites (both with a capacity of 18.9 mb) were already completed in the second half of 2011 and Tianjin (22 mb) was completed in 2012. The complete list of locations has not been officially disclosed, although the other four potential facilities are believed to be underground, located inland near refinery centres and important pipelines, or to be expansions of existing storage sites.

With the SPR-III, China aims to complete construction of its total SPR capacity. Many regional administrations have expressed an interest in holding stocks but it is uncertain whether these are included under the national SPR plan. Several reports indicate that sites earmarked for development may include Wanzhou, Hainan and Caofeidian, although information concerning capacity at individual sites remains obscure.

Stock drawdown and timeframe

When oil market supply is subject to significant changes or unforeseen incidents, the NEA will propose to the State Council its plan for releasing the emergency oil reserves. Following State Council approval, the NEA will carry out the approved actions in co-operation with other stakeholders such as the NDRC, related ministries and the NOCs.

Other measures

Other than using the SPR, China has not yet prepared alternative measures for short-term oil crisis management, such as demand restraint or fuel-switching measures. However, the government has proposed longer-term policies and measures focussing on a more stable and energy efficient economy through promotion of energy efficiency and energy diversification.

Furthermore, although not specifically to reduce oil in an emergency, the Beijing municipal government is reported to be considering the introduction of odd/even licence plate driving restrictions, for the purpose of mitigating pollution. Similar measures were already taken for the Beijing Olympic Games in 2008. Other cities have also conducted a trial run for a similar ban. This experience can be a good example for the future if the country needs to deploy demand restraint measures for oil supply disruptions.

Gas

Market features and key issues

Gas production

China's natural gas production has surged from 27 bcm in 2000 to an estimated 109 bcm in 2012, with a compound average growth rate of about 12%. Coalbed methane (CBM) output reached 12.5 bcm but only 5.2 bcm was utilised, while the rest was flared.

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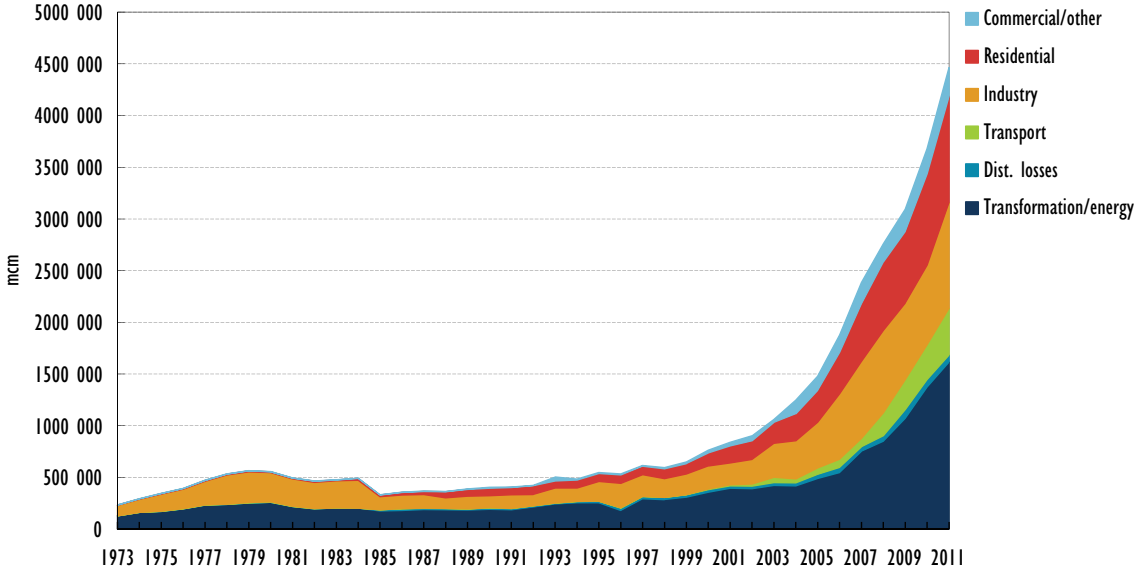
China's natural gas reserves are mainly distributed in nine basins, the main three being Ordos, Sichuan, and Tarim.

Natural gas production in China is expected to reach 137 bcm in 2015 and 172 bcm in 2018, which will make the country the fourth-largest producer behind the United States, the Russian Federation and Qatar. Long-term gas production growth will be supported by a substantial increase in proven gas reserves: 3.5 trillion cubic metres (tcm) for conventional gas, 1 tcm for CBM and 0.6 tcm for proven geological shale gas.

Gas demand

With the development of natural gas pipeline networks, China's demand for natural gas has rapidly increased from 28 bcm in 2000 to around 149 bcm in 2012. It is expected to reach 295 bcm in 2018 – a 12% annual increase since 2012. This is roughly in line with the CNPC's forecasts that Chinese gas demand will reach 350 bcm by 2020. Among the key uncertainties are the pace of GDP growth over the coming years, the timeliness of foreign supplies, notably new LNG supplies (contracted under long-term contracts) and Central Asian gas and the development of unconventional gas.

Figure 5.3.5 Natural gas consumption by sector 1973-2011



In 2011, the transformation/energy sector represented about 36% of the country's total gas consumption, followed by industry (23%), residential (23%) and transport (10%). Gas demand for power generation is expected to increase to 91 bcm, which is almost one-third of China's total gas use. This is entirely dependent on the expansion of gas-fired capacity planned in the Twelfth Five Year Plan. In the transport sector, growth is foreseen to increase from 11 bcm in 2011 to 39 bcm by 2018.

Gas import dependency

China became a net importer of natural gas in 2007. Since then, China's gas imports have gradually increased. It is estimated that China imported about 43 bcm of natural gas in 2012: about 20 bcm in the form of LNG and 23 bcm through pipelines from Central Asia countries such as Turkmenistan and Uzbekistan. With the fastest-growing gas market in the world, China's imports are expected to rise to 122 bcm by 2018.

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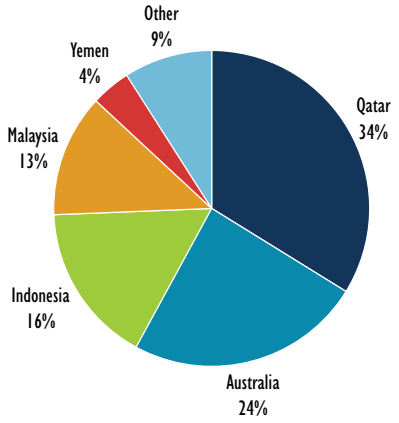
While Uzbekistan began exporting small amounts of pipeline gas to China in August 2012, the bulk of pipeline gas supplies continue to come from Turkmenistan (19.3 bcm in 2012). Turkmenistan plans to increase its natural gas exports to China to 40 bcm per year by 2015 and up to 65 bcm by 2020. Kazakhstan also plans to start exporting to China by 2015, after the completion of the Beineu-Shymkent gas pipeline.

China's LNG imports increased from 16 bcm in 2011 to 20 bcm in 2012. Almost 34% of total LNG imports came from Qatar, while the remaining LNG imports came from Australia (24%), Indonesia (16%) and Malaysia (13%).

Figure 5.3.6 LNG imports by source in 2012



Gas company operations

China's upstream natural gas sector is dominated by CNPC, Sinopec and CNOOC.

CNPC is and will remain the largest gas producer, with three-quarters of its production concentrated in the Changqing, Sichuan and Tarim basins. The company aims to produce 120 bcm by 2015 (from 80 bcm in 2012) and 150 bcm by 2020.

Sinopec is the second-largest gas producer with most of its production coming from Puguang, which reached its plateau of 10 bcm in 2012. Part of Sinopec's incremental gas production is set to be provided by the Daniudi field, whose target lies between 6 bcm and 10 bcm (from 3.7 bcm in 2012).

As for gas distribution, distribution companies are owned and managed by local governments, while most natural gas is delivered to major industrial users directly by producers. Over the past years, the three NOCs have been investing in the downstream sector to get a foothold in the residential sector.

Gas supply infrastructure

Ports and pipelines

China has developed its domestic natural gas pipelines and will continue to meet its growing natural gas demand. The total length of China's natural gas pipelines is estimated at nearly 50 000 km. This includes: the transnational pipeline used mostly for imports (via the West-East II pipeline - east section, the China-Central Asia pipeline - line C, and the West-East III pipeline); 6 000 km of pipelines linking with LNG terminals; and over 12 000 km of major branch and trunk lines, along with 2 054 km of CBM pipelines. China is also expected to increase its pipeline network to over 90 000 km by 2015. Regional gas pipeline networks have been formed in the southwest, the Bohai Rim, Yangtze River Delta, the central south and the northwest.

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Regarding transnational pipelines, the West to East Pipeline has a total length of 3 843 km running from the Tarim Basin in Xinjiang to Shanghai with an importing capacity of 12 bcm per year. The West to East Pipeline II (8 704 km long) became operational in 2012 with a capacity of 30 bcm per year, running from Horgos in Xinjiang province to Shanghai, Guangzhou and Hong Kong. Construction started on the eastern part of the West-East Pipeline III in May 2013. It will be 7 378 km long (of which 5 220 km will be trunk line) with a capacity of 30 bcm per year. This third phase is expected to become fully operational by 2015.

CNPC also brought the China-Myanmar gas pipeline into full operation in October 2013. It consists of a 793 km long trunk line in Myanmar with 1 727 km in China. This pipeline has a combined send-out capacity of 12 bcm to Yunnan province in South China.

China is expanding not only its pipeline capacity but also its LNG regasification capacity. The country started importing LNG in 2006 and has ten LNG terminals in operation with a total regasification capacity of some 46 bcm. Eight LNG terminals are reported to be under construction or being expanded. This would increase China's total LNG regasification capacity to around 70 bcm in the coming years.

Storage

In order to prevent a repeat of the gas shortage in the winter of 2009, the Chinese government has promoted the construction of gas storage facilities. Gas storage at Jintan, Dagang and the Huabei field have contributed to improving the natural gas network for seasonal peak shaving.

In addition to these, CNPC brought into operation the country's largest underground gas storage facility in Hutob in July 2013. This facility has a combined storage capacity of 10.7 bcm for the West-East Gas Pipeline. CNPC has been constructing five other large gas storage facilities. Sinopec's second gas storage facility has also been developed in Zhongyuan, with a capacity of 10.4 bcm, in addition to its existing capacity of around 0.5 bcm. It is reported that China has plans to construct over 35 underground storages in total to boost its storage capacity to 35 bcm by 2015 and to 60 bcm by 2020.

China's LNG terminals also have a combined storage capacity of 2.2 bcm. When all its LNG terminals being planned or under construction are completed, they will add over 4.2 bcm to China's combined storage capacity at LNG terminals.

Emergency policy

Since China was not a net importer until 2007 and its consumption of natural gas was quite limited compared to other fossil fuels, an emergency policy for natural gas disruption was not highly prioritised. However, in addition to the gradually increasing demand for natural gas and after a gas shortage in the winter of 2009, in 2010 the NDRC and the NEA started to formulate a response plan in co-operation with oil and gas companies. The key elements of this plan are to further promote domestic natural gas production, to construct gas storage facilities and to accelerate construction of LNG terminals and interregional gas pipelines in order to strengthen the supply of gas imports.

Since this plan is not public, detailed information is not available. However, the government is considering enhancing its readiness and preparedness for gas supply disruptions as natural gas becomes an important energy source. In November 2013, the NOCs are reported to have started to cut natural gas supplies to industrial consumers, and the chemical sector in particular, to ensure natural gas supply for the residential and transport sectors.

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India

Key data

Table 5.4.1 Key oil data

	1990	2000	2005	2010	2011	2012	2018*
Production (kb/d)	716.0	772.0	774.0	889.0	896.0	883.0	802.1
Demand (kb/d)	1231.0	2350.0	2573.0	3403.0	3526.0	3652.1	4364.1
Net imports (kb/d)	515.0	1578.0	1799.0	2514.0	2630.0	2769.1	3562.0
Import dependency (%)	42	67	70	74	75	76	82
Refining capacity (kb/d)	1067	2116	2674	4249	4377	-	4822
Oil in TPES (%)	19	25	23	22	22	-	-

* Forecast.

Table 5.4.2 Key natural gas data

	1990	2000	2005	2010	2011	2012*	2018**
Production (mcm/y)	12 766	27 860	31 325	51 220	46 455	40 416	55 522
Demand (mcm/y)	12 766	27 860	38 308	63 280	60 473	56 316	-
Net imports (mcm/y)	0	0	6 983	12 060	14 018	-	-
Import dependency (%)	0	0	18	19	23	-	-
Natural gas in TPES (%)	3	5	6	7	7	-	-

* 2012 data are estimates.
** Forecast.

Note: This section was written by the IEA, based on information provided by the Government of India during the Emergency Response Assessment, public information, IEA statistics, press reports and reports from various energy analysts. It does not necessarily represent the official view of the Indian government. All errors and omissions are solely the responsibility of the IEA.

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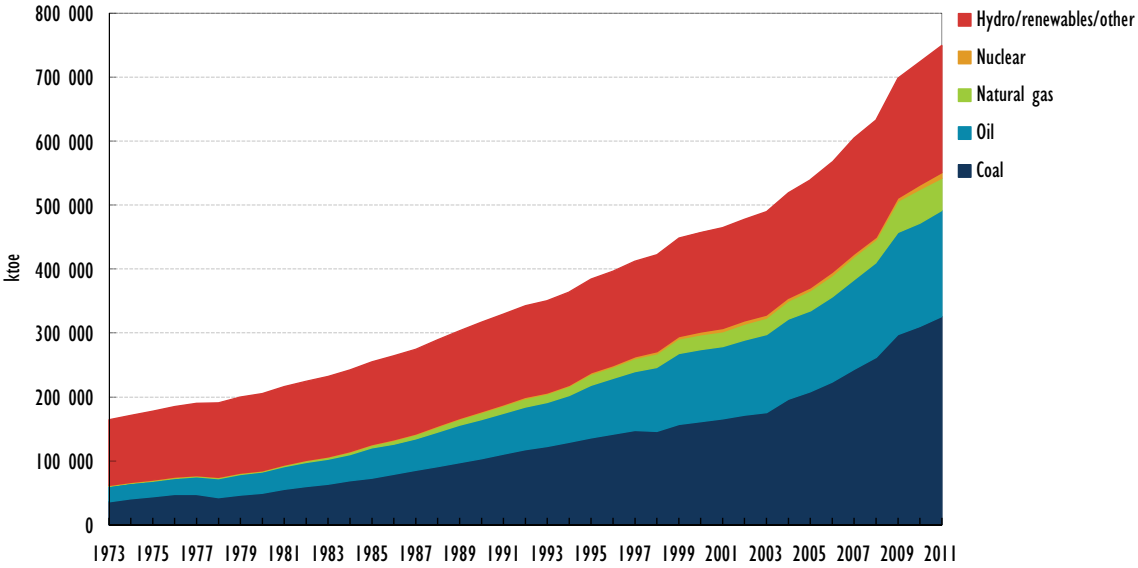
Figure 5.4.1 Total primary energy source (TPES) trend, 1973-2012



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Map 5.4.1 Oil infrastructure of India

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Map 5.4.2 Gas infrastructure of India

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Country overview

India's demand for oil and gas has been increasing significantly in recent years boosted by its rapid economic growth. By 2013, India had become the world's fourth largest oil consumer, consuming 3.7 million barrels a day (mb/d). It is forecast to reach 4.4 mb/d by 2018, when it will overtake Japan as the third largest consumer of oil. This growth in oil demand has also made India the fourth largest oil importer since 2011, importing around 3.5 mb/d of crude. India's limited oil production has been slowly declining and is expected to continue declining, thereby increasing its dependence on imports and allaying its concerns over energy security.

Oil accounted for 22% of India's total primary energy supply (TPES) in 2011, with 40% powering the transport sector. The rapid growth expected in oil consumption in India to 2035 is driven primarily by the explosion of car ownership. Much of India's crude oil imports originate in the Middle East – 69% in the fiscal year 2011/12 – and feed its 22 refineries, with an estimated combined capacity of 4.4 million barrels a day (mb/d). Indian refineries run at 4.3 mb/d with an estimated 1.3 mb/d of that production being exported.

During an oil supply disruption India would rely primarily on its Oil Industry Contingency Plan (OICP) to deal with the oil shortage. Nevertheless, in a severe disaster caused by a natural catastrophe it would invoke the Disaster Management Act, which is geared towards dealing with larger disasters and not specifically oil or gas disruptions. The OICP has as its objective to maintain uninterrupted supplies of petroleum products all over the country and specifically to priority sectors during crises. Even though it is apparent that industry regularly rehearses different disruption scenarios (such as fires at refineries), India remains vulnerable to severe external supply disruptions. Having identified this vulnerability, India's Integrated Energy Policy (2008) recommended creating emergency oil stocks to cover 90 days of oil imports. India has been completing the first phase of its Strategic Petroleum Reserve (SPR), which comprises three sites with a total storage capacity of around 39 mb. The caverns should be ready for filling in 2014. A second more ambitious phase foresees the construction of additional storage sites with a total capacity of approximately 92 mb.

India's natural gas demand reached 65 billion cubic metres (bcm) in 2011 and accounted for only 8% of India's energy mix. As with oil, India's natural gas reserves are considered to be quite small. It produced around 40 bcm of natural gas in 2012, and imports the remaining 17.5 bcm in the form of liquefied natural gas (LNG) from Qatar, mainly to its two terminals located off its western coast. India has a two-market structure for natural gas: the first tier is a regulated market for domestically produced gas which feeds power generation, fertiliser production, city gas distribution and the liquid petroleum gas (LPG) and steel industries; the second tier is an unregulated market based on imported LNG, sold at free pricing on a cost basis. As the price difference between the two markets is considerable, demand far outstrips supply with only certain sectors willing to pay the international LNG prices (in some cases willing buyers do not have physical access to this gas). Therefore the notion of natural gas emergencies differs considerably from that in International Energy Agency (IEA) member countries.

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Oil

Market features and key issues

Domestic oil production

India had about 5.7 billion barrels of proven reserves at the end of 2012. Crude oil production in India during the fiscal year 2011/12 reached approximately 0.8 mb/d. The government's 12th Five-Year Plan foresees a 20% growth in production to 2014/15, when production is set to reach approximately 0.92 mb/d, before gradually declining to approximately 0.83 mb/d at the end of the forecast period of the plan (2016/17). According to the *World Energy Outlook 2013* (*WEO 2013*), India's production rates are set to decline at a compound annual average rate of 1.4% from 2011 to 2035 when oil production is forecast to fall to around 0.6 mb/d. About 51% of India's crude production was onshore in 2012.

In order to boost exploration and production against the backdrop of increasing domestic demand, in 1997/98 India introduced the New Exploration Licensing Policy to provide an equal platform for both public and private sector companies in the exploration and production of hydrocarbons, thus providing a level playing field for all players.

Oil demand

Boosted by high growth rates, India's oil demand has been increasing considerably since 2001. From 2000 to 2011, total oil demand grew at a compound annual rate of 3.6%, reaching 3.5 mb/d. The Indian 12th Five-Year Plan foresees demand reaching about 4 mb/d by 2016/17.

The *WEO 2013 (New policies scenario)* forecasts a compound average annual growth rate of 3.6% from 2012 to 2035. Therefore, by 2020 India is projected to consume 4.7 mb/d, overtaking Japan as the third largest global consumer of oil and responsible for almost 5% of world oil demand. It is also foreseen that by 2035, India's oil demand will have reached 8.1 mb/d. It is also worth noting that the *WEO 2013* sees India as being responsible for the largest share of incremental global oil demand over the period from 2020 to 2035, considerably exceeding Chinese incremental growth.

In terms of oil consumption by sector, IEA figures show that the transport sector accounted for approximately 40% of India's total oil demand in 2011; this proportion has been increasing since the turn of the century. Transport is expected to be one of the key drivers of oil demand in the coming years, spurred on by an increase in India's vehicle fleet.

In 2011, according to IEA figures, oil consumption in the industry, residential and non-energy (transformation, industry or energy) sectors each accounted for roughly one-fifth of oil consumption.

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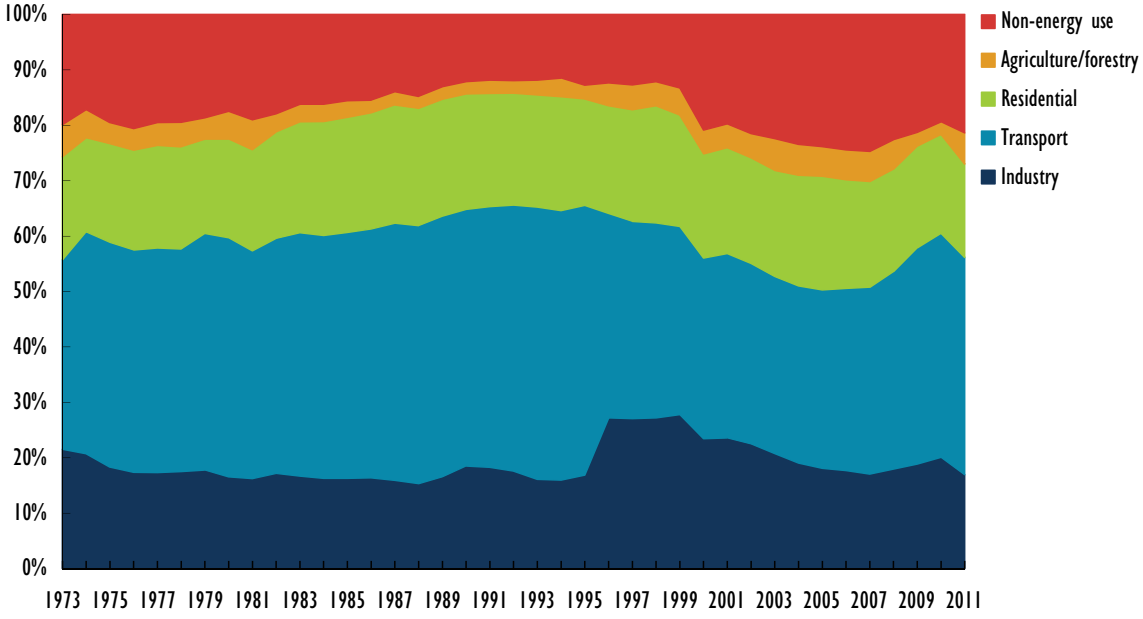
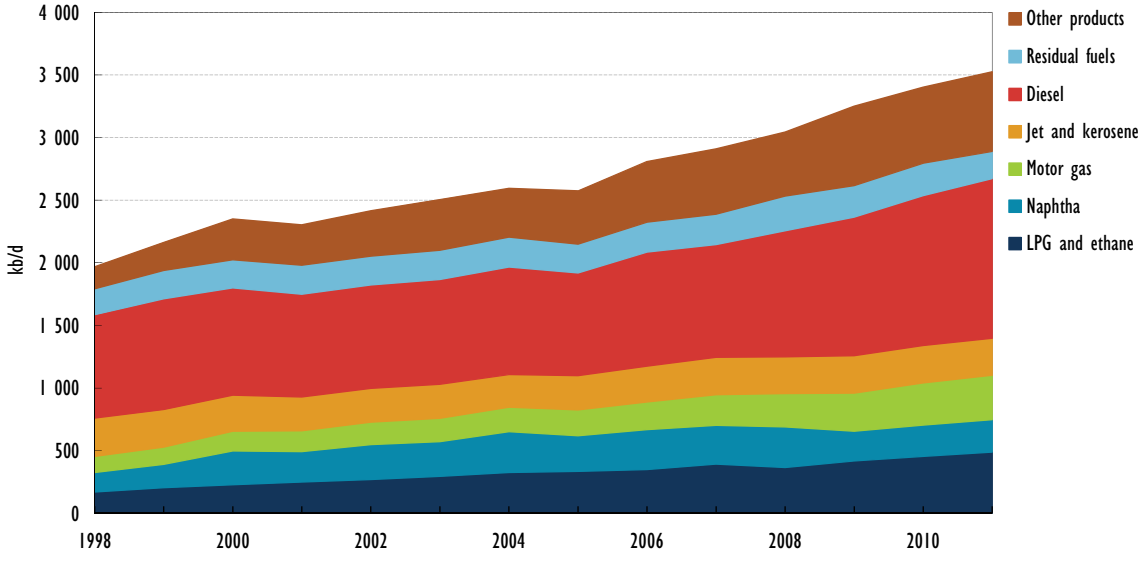
Figure 5.4.2 Oil consumption by sector, 1973-2011



Imports/exports and import dependency

During 2012/13, India imported approximately 3.7 mb/d of crude oil and a little over 400 thousand barrels per day (kb/d) of oil products, primarily LPG. Some 2.3 mb/d, or about 62% of the crude imported into India came from the Middle East, with the large majority originating in Saudi Arabia (19.8%) and Iraq (13%). The rest (around 417 kb/d) came from Africa, primarily Nigeria and Angola. India's dependence on Middle Eastern oil has been relatively stable since the turn of the century, fluctuating from 73.7% (2007/08) to 62.4% (2012/13).

Figure 5.4.3 Oil demand by product, 1998-2012



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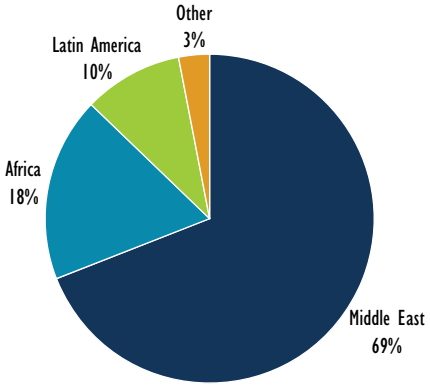
Oil company operations

India's upstream production was predominately a government domain led by the Oil and Natural Gas Corporation (ONGC) and Oil India Limited. Although prior to 1999 there were some joint ventures between state companies and private companies, since 1999 deregulation through the New Exploration Licensing Policy has allowed the participation of private companies in the upstream sector. Today, mainly domestic Indian firms are represented in the sector: ONGC, Oil India Limited (OIL), Reliance, Essar Oil, Cairn Energy and Nikko.

Similarly to the upstream sector, both government-controlled Public Sector Undertakings (PSU) and private companies participate in India's downstream sector. The main PSU players are the: Indian Oil Corporation Limited (IOCL); Bharat Petroleum Corporation Limited (BPCL); and Hindustan Petroleum Corporation Limited (HPCL). Essar Oil and Reliance Industries Limited (RIL) are the most important private Indian oil companies.

Figure 5.4.4 Crude oil imports by origin, 2011-2012



Oil supply infrastructure

Refining

Since 2002, India's refining capacity has been expanding considerably, at least three-fold from around 70 million tonnes (Mt) (or 1.4 mb/d) to 215 Mt (4.4 mb/d) in 2013. At the end of 2012, there were 22 refineries in India with a combined refining capacity of 4.4 mb/d. The PSUs control around 59% of the refining capacity, while the private sector holds the remaining 41%. The three largest refineries are privately owned. Two of them are owned by RIL and are situated in Jamnagar (western India) on the bay of Kutch. This complex had a refining throughput of 1.3 mb/d in 2012. Apart from these refineries which are primarily export-oriented, most other refineries are located close to the major consumption centres. The largest government-run refineries are: Panipat (IOCL) with a throughput of 300 kb/d, which is situated north of Delhi; and Koyali (IOCL), in the Gujarat region. Both are fed by imports arriving in the Jamnagar/Vadinar area. Koyali has a refining throughput of around 275 kb/d. The 2013 *Medium-Term Oil Market Report* foresees an expansion in India's refining capacity reaching 4.8 mb/d by 2018.

India produces a surplus in the majority of its refined products except LPG, which it imports. Since the turn of the century India has been refining much more diesel, gasoline and naphtha than it consumes domestically.

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Ports and pipelines

There are 12 major crude oil ports in India, with a total handling capacity of around 5.5 mb/d. The major crude oil ports are in Vadinar (1.3 mb/d), Jamnagar (1.2 mb/d) and Jawahardeep in Mumbai (865 kb/d). There are also 16 major oil ports handling finished products around the coast of India. These ports have a combined handling capacity of around 2.8 mb/d.

India has a substantial number of crude oil pipelines throughout the country, although there are no linkages between the east and west, or south and north. The largest pipeline has a capacity of 420 kb/d, and serves both Mathura and Panipat refineries from Vadinar. There is a large network of pipelines in the west of India around the Gujarat region going north past Delhi. Most crude pipelines are owned by the ONGC. The IOCL owns the three longest ones, two serving the Panipat refinery (north of Delhi). India's crude oil pipelines have an estimated combined capacity of 2 mb/d.

Oil product pipelines are also numerous in India and are owned by seven different companies, with IOCL controlling the large majority. Most of these pipelines are rather small in capacity with the largest having a capacity of 107 kb/d. India's three LPG pipelines have an estimated capacity of around 123 kb/d.

Storage capacity

Because of the expansion of the refining sector, the storage of crude and refined product throughout India has had to increase. As of April 2013, combined commercial stocks at refineries throughout India stood at around 70 mb. On average, that is enough to keep refineries running for about 16 days. Storage is located at 20 locations throughout the country, but there is some considerable variation in crude storage levels. As of May 2013, in refineries with a capacity of over 150 kb/d, days of cover ranged from 8 days to almost 34 days. There are however a few inland refineries with very limited storage and days of cover. India has no public crude storage sites but will finalise the first phase of its SPR Plan by 2014.

India's total storage capacity for major refined oil products, namely motor gasoline and high-speed diesel is around 17.6 million litres or 110 mb in 2012. In addition to this, there is about 9 mb of capacity for LPG in an underground cavern in Visakhapatnam. Storage of crude oil is located around the main refineries throughout the country.

Given current oil product demand, as of May 2013 days of cover for each product range from 12 to 27 days for the selected oil products. It is worth noting that the utilisation of storage capacity varied considerably by fuel type; from 65% for LPG to under 40% for other products.

Decision-making structure

The Government of India sees its emergency response policy for oil as being a multi-pronged strategy. The National Crisis Management Committee, headed by the cabinet secretary, co-ordinates responses to emergencies. Each ministry is tasked with developing a crisis management plan which outlines the organisational structure and decision-making process.

Furthermore, in 2005 the Indian government passed the Disaster Management Act (DMA) which has created the National Disaster Management Authority (NDMA), headed by the prime minister; State Disaster Management Authorities (SDMAs) headed by the chief ministers; and District Disaster Management Authorities (DDMAs), headed by the collector or district magistrate or deputy commissioner as the case may be, to spearhead and adopt a holistic and integrated approach to disaster management. This mechanism is cited by the government as one of its key tools to deal with all emergencies, not specifically to deal with oil or gas supply disruptions.

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During an oil supply disruption, the OICP would be invoked. The oil industry has formulated the OICP with the key objective being to maintain uninterrupted supplies of petroleum products to all parts of the country and specifically to the priority sectors during crisis situations (utilities, the transport sector). The latest policy was formulated in 2008 and is updated regularly.

In addition, during a crisis, the central government can invoke Section 43 (1) of The Petroleum and Natural Gas Regulatory Board Act 2006, which allows the government to take over control of the entire downstream sector. The same act stipulates that before doing so, the government should consult the affected entities. However, "in case of any urgency or in cases where the circumstances do not permit serving of notice", the opportunity of a consultation may be dispensed with in order to maintain an uninterrupted supply of petroleum.

This power is akin to what is found in many IEA member countries, where governments have the ultimate power to take control and manage oil and gas supplies; however, these powers tend to be reserved for war-time use, or exceptional circumstances going well beyond a disruption in the supply of oil or gas.

It is worth noting that this additional tool is not considered an option in most cases and is therefore not necessarily regarded as part of the government's immediate strategy to deal with oil and gas disruptions.

National emergency security organisation structure

The Government of India has no specific national emergency security organisation (NESO). During a large-scale national disaster the NDMA, the nodal agency for responding to all emergencies and disasters in India, would be activated.

India's NDMA and its structure are very robust, although it is more intuitively geared towards dealing with major natural disasters, rather than specifically with oil or gas disruptions.

Stocks

Stockholding structure

In January 2004, the union cabinet of India officially decided to establish an SPR. In 2008, the government approved the construction of the first phase of its Indian SPR. The first phase envisaged the construction of 5.33 Mt (39.3mb) of strategic storage of crude oil reserves at three locations.

The construction of the sites is conducted under the auspices of the Oil Industry Development Board (OIDB). To implement and manage the proposed strategic crude oil storage projects, a Special Purpose Vehicle (SPV), the Indian Strategic Petroleum Reserves Limited (ISPRL) was formed in June 2004. ISPRL is owned by the OIDB, and headed by a board of directors comprising the secretary of the Ministry of Petroleum and Natural Gas (MoPNG), the additional secretary of the MoPNG, the joint secretary (Refining) of the MoPNG and the secretary of the OIDB.

In December 2011, the secretary of the MoPNG stated that the Indian government was planning to significantly expand the 39 mb stockpile under construction by building an additional 92 mb (12.5 Mt) of storage capacity. The government has been considering establishing four new crude oil storage facilities. The detailed feasibility study for construction of the facilities is being prepared by ISPRL. The new sites are expected to be located in the southern state of Karnataka, in western Gujarat state, in eastern Orissa state and in Rajasthan in the northwest.

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To make decisions regarding the release and replenishment of stocks, the government foresees the creation an empowered committee constituted of government officials. This committee would be chaired by the secretary of the MoPNG.

India places no obligation on its industry to hold a specific amount of stocks.

Crude or products

All stocks are expected to be held in the form of crude oil.

Location and availability

The reserves are being built in underground caverns at Visakhapatnam on the eastern coast of India, in Mangalore on the southwestern coast and in Padur near Mangalore.

Financing and fees

In 2006, the Cabinet Committee on Economic Affairs decided that the filling of the storage would be funded by receipts for the Oil Industry Development Fund under the OIDB Act of 1974 or through a combination using OIDB funds, surcharges on petroleum products and a 2% increase in customs duty. In 2011, in light of the substantial increase in crude oil prices, MoPNG began looking at different options.

Other measures

India has no policy to reduce demand during an oil supply emergency. During an emergency the government could invoke the Essential Commodities Act of 1955 to maintain equitable distribution of petroleum products. The government recognises that the provisions of this act would allow it to control the supplies of certain products to the forecourts but India has no set demand restraint plan which could be set in motion during a supply disruption.

With respect to surge production, given that production rates have been declining, and are expected to continue declining, it is not considered a measure that would bring additional barrels to the market during an oil supply disruption.

Other measures, such as fuel switching or switching away from oil in a disruption have not been studied sufficiently to allow for estimates of this potential and there are no legal instruments for the initiation of such actions. Nevertheless, given that a large amount of backup generation runs on diesel, there could be some potential to reduce the demand for this product, or at least to restrict its purchase during a supply disruption, so that diesel is not diverted to power generation.

Gas

Market features and key issues

Gas production and reserves

Production from India's gas fields has been largely stagnating in recent years. In 2012, supply was around 40 bcm. It is projected to increase to 62 bcm by 2020, and 98 bcm by 2035 (*WEO 2013*). According to Indian figures gas production in India stands at around 47.5 bcm (2011/12), having suffered from a fall in production in a basin off India's east coast (the KG D6). Of the total 124 mcm/d produced in India in March 2012, ONGC

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contributed with 53%, OIL 6%, and private producers 41%. The Krishna Godavari Basin D6 (KG D6) field accounted for 26% of all Indian production. This large gas discovery in 2002 at the KG D6 field raised expectations for India's future gas supply, but it proved to be short-lived and production fell dramatically soon after it started producing.

About 80% of India's gas production comes from offshore fields. Onshore production is dominated by four states: Assam in the northeast, Gujarat in the west and Tamil Nadu and Andhra Pradesh in the southeast which jointly account for close to 90% of production. India produces slightly under three-quarters of its domestic gas consumption.

Gas demand

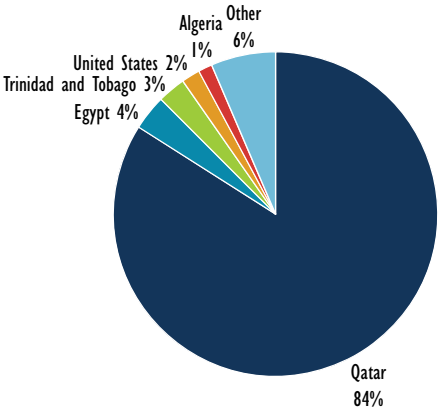
Consumption in India is estimated at around 65 bcm according to official Indian figures in 2011/12 (56 bcm according to IEA figures). Based on the projections made in the 12th Five-Year Plan this figure is set to increase to about 172 bcm in 2016/17. Between 2012 and 2013, about 46% of gas consumption went to power generation, followed by 21% for the fertiliser industry and 18% to the petrochemical industry. The proportions are expected to remain relatively unchanged for the forecast period of the 12th Five-Year Plan.

Gas import dependency

Imports accounted for almost 28% of India's total gas supply in 2011/12, with the share of imports expected to increase to almost 42% by 2017 according to the 12th Five-Year Plan. This is due to stagnating domestic supply. However, actual usage of LNG regasification capacity will depend not only on providing the necessary transport infrastructure, but also on international LNG price development. Total regasification capacity is estimated at 27 bcm/year in 2012.

In 2012, India imported 13.98 Mt, or 19 bcm of natural gas in the form of LNG. According to government projections, LNG imports are set to continually increase in the coming years to meet rising demand in India. The 12th Five-Year Plan foresees LNG imports reaching 55 bcm in the 2016/17. As demand far outstrips supply, all natural gas produced is consumed; however import volumes of LNG remain relatively low as prices are much higher than for domestically produced gas.

Figure 5.4.5 Natural gas imports by source in 2011



Gas company operations

The gas sector was fully opened to private investment in 1999. India's natural gas supply from domestic fields was about 111.3 mcm/d in 2012/13. The main producers of gas are

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government-owned public sector companies, ONGC and OIL, and, in the private sector, RIL (RIL has two foreign partners: BP and Nikko). Through joint ventures the following companies also produce gas: BG Group, Reliance, Cairn Energy and ONGC.

The majority of gas transmission in India is carried out by a public sector company, GAIL India Ltd.

Pricing

India's natural gas prices are regulated and set at different levels for gas originating from different producers. Gas from fields allocated to PSUs by the government is sold at prices set by the government under the Administrative Pricing Mechanism (APM). Joint venture gas producers are paid based on a formula pegged loosely to international prices according to their production sharing contracts but the government maintains close oversight of price adjustments. Gas prices in these JVs cover a wide band; they range from USD 3.5/MBtu (British thermal unit) to 5.65/MBtu. Gas from NELP fields was supposed to be sold at market prices set through a price discovery process. Following the first gas price discovery process, the price for NELP gas was fixed at USD 4.2/MBtu in 2009 based on an oil-indexed price formula. This has since been revised, with new price effective as of April 2014.

However, the price of regasified LNG is based on different supply contracts, long and short-term supplies as well as spot prices. Short-term supplies and spot cargoes carry substantially higher prices than domestically produced gas and long-term supply contracts for LNG. According to some reports, India paid between USD 9/MMBtu and USD 12/MMBtu for LNG imports in 2012/13.

Gas supply infrastructure

LNG terminals

India has four LNG terminals:

- The Dahej Terminal, belonging to Petronet LNG Limited (PLL), has a nameplate capacity of 10 Mt, or 13.6 bcm/y. The Dahej Terminal will be expanded to 12.5 Mt (or 17.2 bcm) by 2013 and to 15 Mt (or 20.6 bcm) by 2016.
- India's second operational LNG terminal is a 3.6 Mt (or 5 bcm) facility owned by Shell in Hazira, which will be expanded to 5 Mt (or 7 bcm) by 2014 and to 10 Mt (or 13.6 bcm) by 2017. Hazira uses short-term sales contracts and sources LNG on demand.
- PLL's second terminal in Kochi, with a capacity of 5 Mt (or 7 bcm), is operational since August 2013 and has secured 1.44 Mt (or 2 bcm) of long-term supplies from Australia's Gorgon field, starting in 2016.
- The Dabhol facility of GAIL has a capacity of 1.2 Mt (or 1.6 bcm) and was commissioned in early 2013. Capacity may be expanded to 5 Mt (or 7 bcm) by 2014.

The 12th Five-Year Plan has ambitious expansion targets for seven LNG regasification terminals in India. It expects capacity to reach 68 bcm/y by 2016/17.

The southern and eastern parts of the country are not connected. A fully developed grid would allow gas-fired power generation and gas for industrial use to be spread throughout the country and to provide anchor load for other users such as city gas and Compressed Natural Gas. Many potential and solvent gas consumers are unable to access the gas because of a lack of regional infrastructure. India has no cross-border pipelines.

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Gas pipelines

India's gas transmission infrastructure is mainly concentrated in the northern and western parts of the country, reflecting historical gas production and consumption centres. The entire natural gas network comprises 15 283 km, with a total capacity of about 400 mcm/d. Approximately 15 000 km of additional pipelines are to be put into operation during the 12th Five-Year Plan, increasing total natural gas pipeline capacity to 876 mcm/d. The government also envisages that by the end of the 13th Five-Year plan another 13 500 km of pipelines would be added, increasing capacity by 300 mcm/y. GAIL is the quasi-monopoly operator of cross-national pipelines with a network of almost 11 000 km. ONGC also owns a small proportion of the network, and only a small number of pipelines are owned by the private sector (joint ventures).

Storage

There are no stand-alone natural gas storage facilities in India, although there are very limited storage facilities at regasification terminals. In 2013, there were ten tanks with a storage capacity of around 1.5 mcm at the four terminals, or roughly 0.01% of imports.

Emergency policy

Natural gas represents only 8% of India's TPES. This proportion is expected to increase only very moderately to 2035, when it is forecast to reach a little over 9% (*WEO 2013, New policies scenario*). Furthermore, India runs a dual-pricing model for natural gas: domestically produced natural gas is essentially directed to prioritised sectors; LNG, bought relatively freely, is expensive. The combination of these two pricing structures illustrates that demand will continue to outstrip supply. This would remain unchanged until these prices converge considerably, especially if the price of locally produced gas reaches a more comfortable level which would entice exploration and investment. This dual-pricing structure creates a situation unlike what is experienced in IEA member countries, where availability of gas dictates demand. For instance, although electricity scarcity is common in India there are a number of natural gas-fired power plants sitting idle as it is uneconomical to produce electricity with imported LNG. With the pricing regime being revisited, this could have positive implications for the appetite of industry to increase exploration in India, and could, potentially, lead to increased domestic supply.

In a study commissioned by the Petroleum Federation of India on the "Impact of Gas on Refining and Marketing" in 2011, one of the conclusions advanced was that India could theoretically displace around 44 Mt of liquid fuel by 2016/17 with a volume of about 140 mcm/d of natural gas. This would constitute 23% of the projected consumption of liquid fuel in 2016/17 and is a reflection of the potential of gas to reduce India's oil import dependency.

As for oil, the government can invoke Section 43 (1) of The Petroleum and Natural Gas Regulatory Board Act 2006, allowing it to take control of gas supplies, but this seems to be much more pertinent in case of war or natural disaster than in relation to a disruption in supply.

There also seems to be some potential for fuel switching, as some industries, such as power plants (gas-oil-coal), fertiliser plants (gas-fuel oil) and the transport sector (gas-petrol) have the capability to switch fuel from natural gas to either oil, coal or to other fuels during a crisis. However, no formal analysis has been carried out and at present there is no legal instrument concerning fuel switching.

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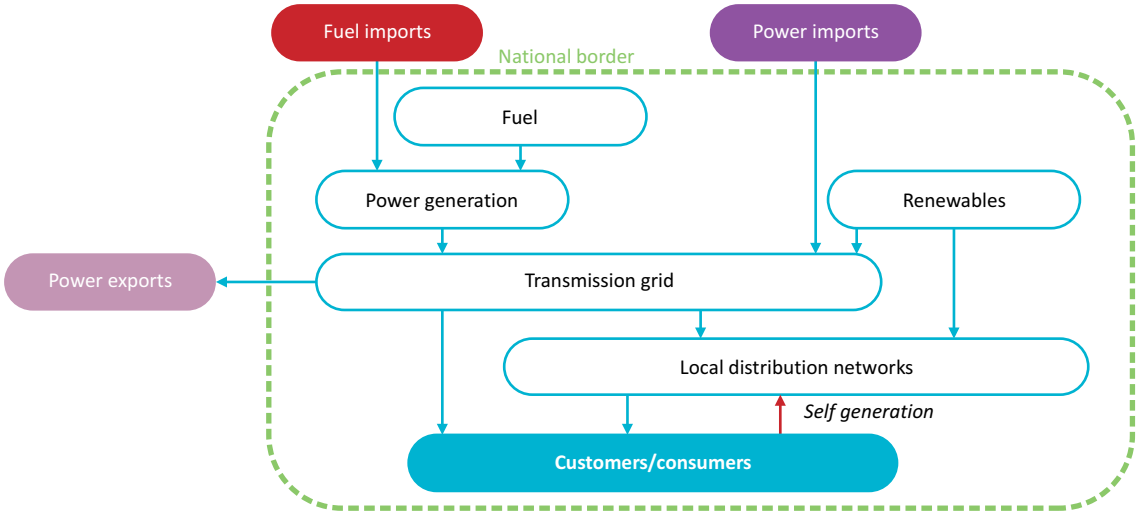
Assessing electricity security

Introduction

Maintaining reliable and resilient power systems is an evolving challenge. Policies to improve energy efficiency and promote decarbonisation through increased variable renewable generation create a more dynamic regional and real-time operating environment. More volatile patterns of usage, combined with policy, regulatory and economic uncertainty, create a more complex infrastructure investment environment. In addition, ongoing geo-political instability in some producing regions and persistent concerns over security of natural gas supplies and related transportation to Europe highlight the vulnerability of fuel supply chains and the price volatility created by tight supply-demand conditions.

Figure A.1 Breakdown of the electricity supply chain



Note: unless otherwise indicated, all tables, figures and in this annex derive from IEA data and analysis.

The IEA definition of "power system" encompasses the whole value chain, including end-use and related laws, rules, regulations and institutional and market arrangements governing electricity sector operation and development. Power systems need to become more responsive and innovative – both in how they operate in the present and how they develop into the future – if they are to continue to deliver electricity security in a cost-effective manner.

The IEA Secretariat has developed an integrated assessment framework to incorporate electricity security assessments into emergency response reviews. The new framework is being implemented from October 2013.

Supply trends in power systems

Countries need well-functioning markets more than ever before to create strong incentives for timely, efficient and innovative investment and operational and end-use responses to maintain electricity security. Governments will need to adopt policies,

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regulations, market rules and implement support programmes that more effectively complement and reinforce these incentives. The IEA considered four key strategic areas to assess electricity security:

- **Electricity sector unbundling:** In the past, most countries had vertically-integrated electricity systems with a single system operator making all decisions about investment in electricity security. Over the past few decades, most OECD member countries have reformed their power sectors to be more transparent and open to competition. System operators must now make decisions with many smaller players in the electricity market, who are competing on cost and services provided. Formerly integrated planning, development and operations of network services now have to be co-ordinated with the rest of the sector. This requires regulatory responses with a whole-of-system view as well as competitive service pricing and service price exposure.
- **Generation adequacy:** The introduction of competitive electricity market arrangements has shifted investment risks into generation assets from consumers to investors. At the same time governments often express the need for certain reliability targets of electricity supply (e.g. one-in-ten events) and the willingness to protect consumers from abuse of market power through administered price caps. Keeping an efficient level of generation adequacy in competitive markets requires sophisticated sector governance. The demand for such frameworks may rise with growing system dynamics and depressed market prices (eg through lower fuel prices as in Texas or the merit order effect from renewable resources). Issues concerning generation adequacy generally play out over medium-long term time frames, so are not generally considered during Emergency Response Reviews.
- **Regional market integration:** Reforms to the electricity sector have also expanded electricity markets to the regional level, particularly in North American and Europe. Price differences between countries with excess electricity demand and countries with excess generation drive power flows across regions. System operators must now make dispatch decisions with many other operators across countries, increasing the distance travelled by the electricity and making the power eco-system more vulnerable.
- **Variable renewable generation:** Polices to improve efficiency and to promote decarbonisation through increasing variable renewable generation create a more dynamic regional and real-time operating environment. System operators must now be able to balance electricity supply and demand on short notice when the wind stops blowing. Rooftop solar PV panels impact both the transmission and distribution of electricity. As renewable energy sources make up a greater share of the power sector, increased variable generation will increase demand volatility and raise new challenges for maintaining power system security.

Concepts and principles

The key strategic areas listed above all affect electricity reliability to varying extents. IEA defines reliability as the ability of the value chain to deliver electricity to all connected users within acceptable standards and in the amounts desired. Reliability possesses two fundamental dimensions, drawn from those used by the North American Electric Reliability Corporation and the International Council on Large Electric Systems:

- **System security:** The capability of a power system using its existing resources to maintain power supplies in the face of unexpected shocks and sudden disruptions in real-time, such as the unanticipated loss of key generation or network components or rapid changes in demand
- **Adequacy:** The capability of the power system using existing and new resources to meet changes in aggregate power requirements in the present and over time, through timely and flexible investment, operational and end-use responses.

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These dimensions are inter-related. For instance, system security policies and practices help to establish the effective adequacy of existing infrastructure in the present, while efficient, timely and well-located investment maintains power system adequacy and provides the resources needed to maintain system security into the future.

Maintaining access to reliable fuel supplies for power generation is integral to delivering power system security and adequacy. In particular, reliable access to fuel supplies and efficient use of those supplies is required to ensure generating equipment operates reliably and predictably from a short-term power system security perspective, and to ensure that the generating infrastructure is able to meet demand, and hence adequacy requirements, in the present and into the future. Accordingly, the assessment framework incorporates fuel security issues into the discussion of system security and adequacy, as appropriate. Fuel security issues addressed in this context include: diversity of supply and supply routes; storage and fuel reserve management policies; and the ability of fuel supply markets to respond to a rapid and possibly sustained increase in generator fuel demand in response to an emergency event.

Key features of the assessment framework

The Secretariat developed the integrated assessment framework to facilitate high-level peer review of member country electricity security. The framework addresses the key legal, regulatory, institutional, market, operational, end-use, technological and infrastructure-related factors influencing the fundamental determinates of electricity security – i.e. system security and adequacy – and how they interact to affect electricity security outcomes.

Figure A.2 Key features of the assessment framework

Governance and market arrangements

Governance and market arrangements establish the incentives for efficient, flexible, timely and innovative responses to maintain the security and adequacy of the power system over time. Electricity security assessments should consider the extent to which the rules, standards and markets establish effective roles, responsibilities and accountabilities for key parties to individually and collectively deliver electricity security.

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Power system security

Effective real-time management of electricity systems is only possible through centralised or centrally co-ordinated system operation, reflecting the unique characteristics of electricity and the related natural monopoly characteristics of system operation. Where different national power systems are physically interconnected, cross-border management is also important. Electricity generally cannot be cost-effectively stored, so supply and demand must be balanced at every moment and in every location simultaneously to avoid reduced supply quality or even large blackouts. Electricity demand does not generally respond to price changes in the balancing (instantaneous) timeframe. Technical constraints (e.g. ramp up/down rates) limit the availability of additional supply.

As a result, the nature and effectiveness of system operation is generally the main determinant of power system security and should form a central part of the system security assessment. The key dimensions of system operation are contingency planning and resourcing, emergency management and restoration and, where applicable, cross-border management of all these dimensions.

Box A.1 N-1 Secure power systems

A power system can be described as being N-1 secure when it is capable of maintaining normal operations (i.e. reliably delivering electricity of a given frequency and voltage subject to technical limits) following a single contingency event, like the unplanned loss of the largest transmission line, generator or transformer during a period where the system is operating at maximum load. This standard has been adopted by system operators around the world to inform operational contingency planning, to guide management of system operation and to guide emergency efforts to return systems to a stable and secure operating condition within a reasonable time following a single contingency event, usually within 15 to 30 minutes.

Power system adequacy

The nature and volume of reserves determines power system adequacy, including demand response, available to meet dynamic changes in aggregate system demand, production and fuel supply conditions. As a result, resource adequacy, which focuses on the volume of resources and reserves available to address changing power system requirements, will remain a key determinant of power system adequacy. However, the nature of those resources and reserves – particularly in terms of their flexibility and diversity – is becoming increasingly important in the context of assessing power system adequacy and resilience where more dynamic system conditions evolve. Accordingly, electricity security assessments should also consider the flexibility and diversity of resources and reserves as well as the volume of resources available to support power system adequacy.

Short-term adequacy is a function of the operational performance of a power system at a given point in time under a range of operational conditions. This reflects the diversity, flexibility and volume of existing resources and the way they are deployed.

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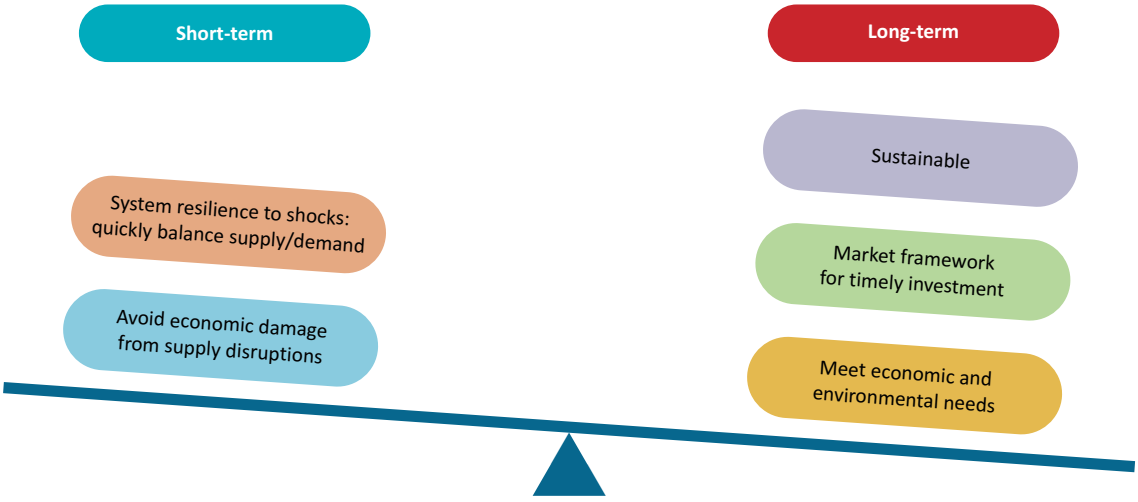
Model of Short-term Energy Supply Security (MOSES)

As the International Energy Agency (IEA) expands the scope of its emergency response reviews to include more energy sources such as natural gas and electricity, it is becoming more important to link these sources together – along with non-energy components such as infrastructure – for a holistic view of risks to a country's energy security. The IEA is developing the Model of Short-Term Energy Security (MOSES[1]) as a comprehensive tool for evaluating short-term security of energy supply in IEA member countries.

MOSES is a generic assessment framework that can be used as a starting point for national studies and can be further supplemented by country-specific indicators. This approach makes it possible to combine and interpret indicators related to various aspects of energy security in a systematic, transparent and policy-relevant way. In addition, MOSES allows for comparisons between countries on national energy security challenges. Such a comparison is a prerequisite for understanding the broader energy security landscape for IEA countries, which, in turn, is necessary for drawing common strategies and responses, as well as for exchanging information and policy experience among countries.

The principal purpose of the model is to support and supplement the emergency response reviews (ERRs) of the IEA. The output of the model should provide an indication of whether measures to mitigate risks to a member country's energy supply are sufficient, highlighting areas on which review teams should focus their attention. Furthermore, the output of the model can provide a point of reference around which a qualitative discussion can take place during ERRs, and it can provide a cross-check against the review team's qualitative assessment of a country's energy security. The model may also be able to show trends in a country's short-term energy security over time, highlighting longer-term energy security issues that may require further investigation.

Figure B.1 The time dimension of energy security



Note: unless otherwise indicated, all tables, figures and in this annex derive from IEA data and analysis.

1. For more detailed information on the MOSES Model, please see the Working Paper on the IEA website www.iea.org/publications/freepublications/publication/name,20557,en.html.

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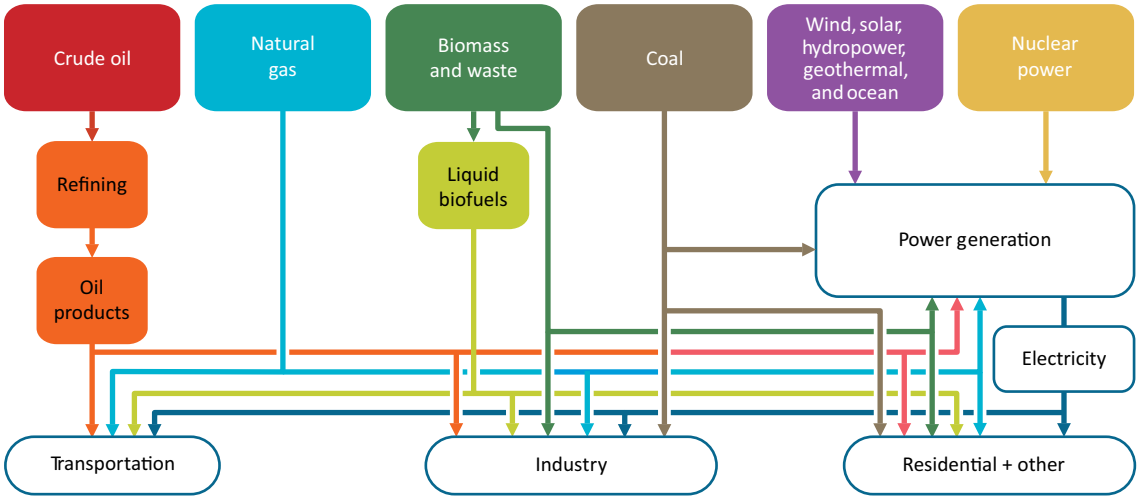
Methodology: An energy systems approach

MOSES does not aim to rank countries on the basis of their energy security. Instead, it identifies energy security profiles of individual countries based on their risks and resilience capacities. Nations with similar energy security profiles are grouped together to depict the overall energy security landscape in IEA countries and to facilitate policy dialogue on common priorities. MOSES can also be used to track the evolution of national energy security profiles over time, to analyse the effect different policies would have on a given country's energy security and aid in identifying national energy policy priorities.

The model takes an energy systems approach in analysing energy security. Energy systems analysis deals with all parts of the energy system from energy supply to transformation and distribution to end-use energy services. In its current version, MOSES considers how vulnerabilities of primary energy sources affect the security of secondary fuels. With its focus on fuels and energy sources, this version of MOSES also lays the groundwork for extending the analysis to security of electricity and end-use sectors.

Figure B.2 Energy systems approach in MOSES



Source: IEA,2011.

As a tool to inform energy security policies by quantifying vulnerabilities of energy systems, MOSES is based on a set of quantitative indicators that measures two aspects of energy security:

- **risks** of energy supply disruptions
- **resilience**, or the ability of a national energy system to cope with such disruptions.

MOSES analyses both risk and resilience connected to **external** factors related to imported energy, as well as **domestic** factors related to domestic production, transformation and distribution of energy. Thus, MOSES includes indicators related to external risks, external resilience, domestic risks and domestic resilience.

These four dimensions are analysed in MOSES using approximately 30 indicators that characterise each primary energy source and secondary fuel. The model evaluates energy supply security using these indicators in two steps. First, each indicator establishes three bands of values – corresponding to low, medium and high vulnerability. These bands are based on the observed ranges of the indicator values in IEA countries, as well as on expert judgements about risks and resilience capacities.

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Table B.1 Dimensions of energy security measured by MOSES

	Risks	Resilience
External	***External risks:*** risks associated with potential disruptions of energy imports	***External resilience:*** ability to respond to disruptions of energy imports by substituting with other suppliers or supply routes
Domestic	***Domestic risks:*** risks arising in connection with domestic production and transformation of energy	***Domestic resilience:*** domestic ability to respond to disruptions in energy supply such as fuel stocks

In the second step, the model combines these indicators to establish an energy security profile for each country. These combinations take into account how particular risks may exacerbate each other and how particular resilience capacities may mitigate specific risks. For example, the number of ports or pipelines mitigates risks of imports but is not relevant for countries with primarily domestic production. In contrast, fuel storage is a resilience factor for both domestically-sourced and imported fuels, since it mitigates risks from both sources.

Limitations and exclusions

Any study of energy security faces a series of choices, and MOSES is no exception. The focus on short-term physical security of primary sources and secondary fuels excludes notions that are more relevant in medium or long-term perspectives on energy security, such as the environmental impact of different energy sources, rapidly growing demand and the depletion of natural resources. Similarly, the model does not capture the economic or affordability dimension of energy security, such as the level and volatility of energy prices, because MOSES focuses on physical security of supply.

Since MOSES relies on quantitative indicators, the model excludes some institutional and investment factors. The security of an energy system is not limited to the state of its infrastructure (the primary focus of MOSES), but also to the effectiveness of its policies and regulations, as well as the market structure and the investment climate. While governance factors can be important for energy security, they are not easily quantified and thus only indirectly reflected in the model.

MOSES aims to evaluate the security of supply of individual primary energy sources and secondary fuels. It is not designed to compare the security of supply across different energy sources, or to produce an overall energy security index spanning several fuels and carriers. Consequently, it cannot be used to compare the overall energy security of different countries, although specific sources and fuels can be compared.

Example: Oil product supply chain and mitigation capacity analysis

Oil products consumed can either be refined domestically or imported. Each of these two supply streams is associated with specific risks and resilience factors. While imported products can be subject to disruption of trade, supply routes or compromised importing infrastructure, domestically refined products are exposed to the risks of refinery outages and disruptions of adequate crude supply.

MOSES breaks down the oil product supply chain as shown in Figure B.3, which shows how imported and domestic crude flow through domestic refineries to end up as inputs

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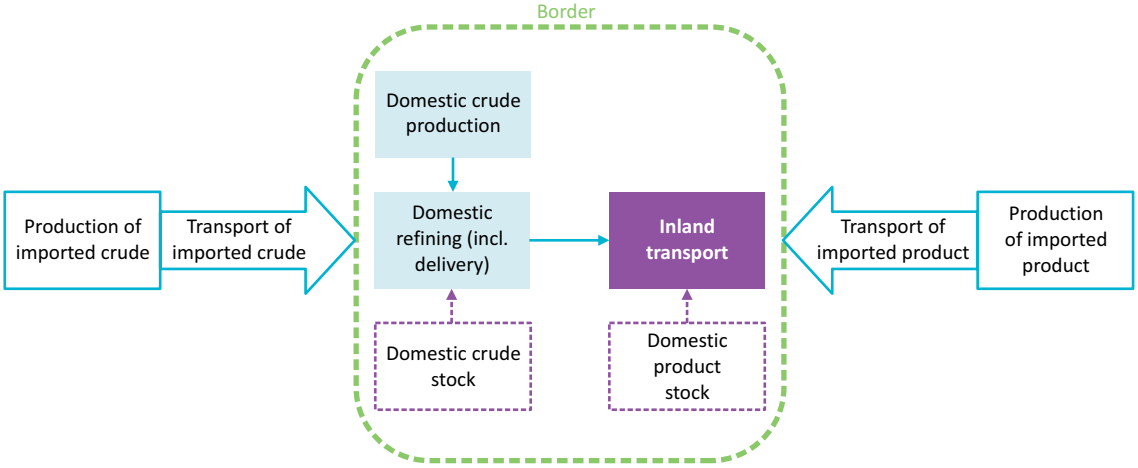
into the inland transport network, and that imported products are directly input into the inland transport network. "Domestic refining" encompasses both the delivery mechanism for a refinery (the associated port or pipeline) and the refinery itself.

The purple dashed boxes represent the domestic crude and product stock that a country can draw upon during disruption contingencies. This category includes all stock that can be counted towards the IEA oil stockholding obligation, including industry working stock.

Figure B.3 Breakdown of oil product supply chain for risk and mitigation analysis



Drawing on stock may not be the only mitigation capacity available to counteract disruptions. In principle each flow into the "inland transport" box should be analysed to understand whether there is spare capacity that can mitigate a given disruption. In practice simplifications are made which result only in product stock, and crude stock that can be domestically refined, being considered.

Continual improvement

The IEA continuously refines and updates both the results and the MOSES methodology. IEA analysts conduct literature reviews on energy security models and discuss possible changes with energy sector experts.

While security of supply is an important element of energy security, ultimately consumers and policy makers alike are most concerned about the security of energy services. Thus, incorporating electricity and then end-uses into MOSES will be key future steps in providing policy-relevant analysis of energy security. In addition, the IEA is currently exploring the area of spatial analysis to assess the impact of geographically-based events, such as storms and earthquakes, on energy infrastructure around the world. Together with MOSES, these tools are part of a wider horizon scanning strategy of the IEA that identifies what factors may shape a country's future energy environment, and what are priority questions for policy makers in that country.

Reference

International Energy Agency (2011),"The IEA Model of Short-term Energy Security (MOSES)", *International Energy Agency Working Paper*, IEA/OECD, Paris.

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Definitions and methodology

This annex provides definitions and methodologies to better understand the data presented in the individual country sections. Unless otherwise noted, data presented in this publication are based on country submissions of energy statistics to the International Energy Agency (IEA), primarily through the questionnaires of monthly and annual oil and natural gas statistics.

Key oil data table definitions

Production	Indigenous production of crude oil, natural gas liquid (NGL) and various types of heavy oil-like hydrocarbons from different location within national boundaries (onshore, offshore). Production includes only marketable production, and excludes volumes returned to formation. It includes various types of heavy oil-like hydrocarbons and natural gas-based, coal-based and renewable-based (biofuel) sources which are used as oil product equivalents and are included in the definition of demand. These non-conventional oils include other hydrocarbons and alcohols, biodiesel, synthetic oil production, oil shales, coal-based and natural gas-based oil substitutes and methane-based blending components such as MTBE (methyl tertiary butyl ether). Data projections for 2018 are based on IEA forecasts from *Medium-Term Oil Market Report 2013 (MTOMR 2013)*. Data in thousand barrels per day.
Demand	This is oil demand derived from total inland deliveries plus refinery fuels and bunkers minus backflows from the petrochemical sector. It is thus equivalent to oil consumption plus any secondary and tertiary stock increases. Data projections for 2018 are based on IEA forecasts from the Oil Medium-Term Market Report, May 2013. Data in thousand barrels per day.
Motor gasoline	Motor gasoline is used as a fuel for land-based spark ignition engines. Motor gasoline may include additives, oxygenates and octane enhancers, including lead compounds such as TEL (tetraethyl lead) and TML (tetramethyl lead). This category includes motor gasoline blending components (excluding additives/oxygenates), e.g. alkylates, isomerate, reformate, cracked gasoline destined for use as finished motor gasoline. Data in thousand barrels per day.
Gas/diesel	Gas/diesel oil includes transport diesel, heating oil and other gasoil. Transport diesel oil is used to power diesel engines in buses, trucks, trains and cars. Heating oil is used to heat domestic/residential and commercial buildings, as well as industrial boilers. Gasoil is also used for power generation, although to a much smaller extent than fuel oil. Data in thousand barrels per day.
Residual fuel oil	This covers all residual (heavy) fuel oils including those obtained by blending. Fuel oil is used by the power generation utilities to produce electricity and heat, by industrial users for process heat and by the commercial sector to provide heating fuel for their buildings. It is also the most important fuel for international marine bunkers. Data in thousand barrels per day.
Others	Includes LPG, ethane, naphtha, kerosene, jet fuel and other petroleum products. Data in thousand barrels per day.
Net imports	This is oil demand minus oil production (a negative number denotes net exports). Data in thousand barrels per day.
Import dependency (%)	This is net oil imports divided by oil demand.
Refining capacity kb/d	This refers to atmospheric crude oil distillation. This is the first stage in the refining process of separating crude oil components at atmospheric pressure by heating and subsequent condensing, of the fractions (unfinished petroleum products) by cooling. The data corresponds to the first of January of the given year. Data in thousand barrels per calendar day (a unit measuring the average rate of oil processing in a petroleum refinery, with allowances for downtime over the year). Based on data from countries and/or IEA estimates.
Oil in TPES	This is total oil supply, including primary (e.g. crude oil and NGLs), secondary inputs to refineries and finished products divided by total primary energy supply (see definition below).

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Key natural gas data table definitions

Production	Indigenous production of natural gas is dry, marketable production within the national boundaries of a country, including offshore production. It is measured after purification and extraction of NGL and sulphur. It does not include quantities re-injected, extraction losses or quantities vented or flared. Data projections for 2018 are based on IEA forecasts from the *Medium-Term Gas Market Report 2013*. Data in million cubic metres per year.
Demand	This is natural gas demand derived from total inland deliveries of marketable gas, including gas used by the gas industry for heating and operation of equipment (i.e. consumption in gas extraction, in the pipeline system and in processing plants) as well as losses during distribution. Data projections for 2018 are based on IEA forecasts from the *Medium-Term Gas Market Report 2013*. Data in million cubic metres per year.
Transformation	This covers natural gas which is transformed into other forms of energy. This includes natural gas used in the generation of electricity and heat, as well as amounts used in coke ovens, blast furnaces and as feedstock for conversion to liquids (e.g. the quantities of fuel entering the methanol production process for transformation into methanol).
Industry	This includes all industrial consumption of gas in support of its primary activities, including gas used as fuel (energy use) and feedstock (non-energy use), for example, in chemical and petrochemical plants.
Residential	This is natural gas used in households.
Others	This is natural gas used in sectors other than transformation, industry and residential. This includes energy (gas used to support extraction or plant operation of transformation activities), transport (gas used for all transport activity irrespective of the economic sector in which the activity occurs), commercial, agricultural and other non-specified sectors.
Net imports	This is natural gas demand minus natural gas production (a negative number denotes net exports). Data in million cubic metres per year.
Import dependency (%)	This is net imports divided by demand.
Natural gas in TPES	This is the total supply of natural gas (excluding NGLs) and gasworks gas divided by the total primary energy supply (see definition below).

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Graph definitions within country sections

Total Primary Energy Supply	Is made up of production + imports - exports - international marine bunkers ± stock changes of the following energy sources:
Coal	Coal includes all coal, both primary (including hard coal and lignite) and derived fuels (including patent fuel, coke oven coke, gas coke, brown coal briquettes (BKB), coke oven gas and blast furnace gas). Peat is also included in this category.
Gas	Gas includes natural gas (excluding NGLs) and gas works gas.
Nuclear	Nuclear shows the primary heat equivalent of the electricity produced by a nuclear power plant with an average thermal efficiency of 33%.
Oil	Includes primary products (e.g. crude oil and NGLs), secondary inputs to refineries and finished products.
Hydro/Renewables/ Other	**This category incorporates:** **Hydro** is the energy content of the electricity produced in hydro power plants. Hydro output excludes output from pumped storage plants. **Combustible renewables and waste** comprises biomass and animal products (wood, vegetal waste, ethanol, animal materials/wastes and sulphite lyes), municipal waste (wastes produced by the residential, commercial and public service sectors that are collected by local authorities for disposal in a central location for the production of heat and/or power) and industrial waste. **Other** includes geothermal, solar, wind, tide, wave energy, electricity and heat. Heat includes heat that is produced for sale and is accounted for in the transformation sector.
Oil consumption by sector	Total oil consumption, classified in the following sectors:
Transformation	Transformation covers oil used in the process of transformation of oil to another energy form, e.g. oil into electricity, heat, etc.
Energy	Covers consumption of oil by the energy transformation industries (for heating, light and operation of equipment) as well as oil used in oil and gas extraction, coal mines, pipeline losses and distribution losses.
Transport	Oil used for all transport activity (aviation, road, rail, domestic navigation, pipeline transport), regardless of the sector in which the activity occurs. This includes all consumption in transport excluding international marine bunkers, but including lubricants, waxes, etc. used in the transport sector. Also includes consumption in support of the operation of oil and gas pipelines.
Industry	This includes all industrial consumption of oil, including consumption of petrochemical feedstocks and non-fuel uses, such as consumption of lubricants, waxes, white spirit, bitumen, etc. Industrial consumption of oil for the production of electricity (autoproduction) is excluded.
Other sectors	Includes residential, commercial and public services, agriculture and other (not specified) use. Consumption of lubricants, waxes, white spirit, etc. are also included.

Other key definitions

Public stocks	Stocks held by a government-owned or industry-owned entity or agency (defined by state legislation), for the purpose of meeting the stock-holding obligation imposed by law of a given country, by the International Energy Agency or any other international organisation.
Inputs to refineries	Comprise crude oil, NGLs, refinery feedstocks and additives as well as other hydrocarbons.
Refined oil products	Petroleum products comprise refinery gas, ethane, LPG, aviation gasoline, motor gasoline, jet fuels, kerosene, gas/diesel oil, heavy fuel oil, naphtha, white spirit, lubricants, bitumen, paraffin waxes, petroleum coke and other petroleum products.
Middle distillates	The aggregate of gas/diesel oil, kerosene-type jet fuel and other kerosene.

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Abbreviations of units

Energy

toe	tonne of oil equivalent
Mtoe	million tonnes of oil equivalent

Gas/capacity

Tcf	thousand cubic feet
mcm	million cubic metres
bcm	billion cubic metres
tcm	trillion cubic metres
kl	kilolitre

Mass

Kt	kilotonnes (1 tonne × 10^3)
Mt	million tonnes (1 tonne × 10^6)
T	tonne

Oil

b/d	barrels per day
kb/d	thousand barrels per day
mb/d	million barrels per day

Power

kW	kilowatt
MW	megawatt
GWh	gigawatt-hour

Conversion factors

Oil data collected from IEA member countries are reported in thousand tonnes. This publication has converted data to barrels using conversion factors based on actual density. Note that, with the exception of European countries, data are generally collected for local purposes in volume terms and converted to tonnes for submission to the IEA. The conversion factors used are therefore the same, to the extent possible, as those used by the countries in making their submissions to ensure correct volumetric data. The following are the average conversion factors and major exceptions used within this publication's calculations.

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Average conversion factors (bbls/metric tonnes)			
Standard		Major exceptions	
Crude oil	7.37		
NGL	10.3	Japan	8.85
		Korea	8.85
Refinery feedstocks	7.4	United States	7.46
Additive	7.5	United States	8.3
Non-crude	7.4	Canada	6.8
		United States	8.3
Refinery gas	8	Australia	9.71
		Canada	6.6
		Japan	6.99
		Korea	6.99
		United States	7.45
Ethane	16.85		
LPG	11.6	Norway	12.73
Naphtha	8.9	OECD Pacific	8.5
		Canada	8.5
		United States	8.5
Aviation gasoline	8.9		
Motor gasoline	8.45	OECD Pacific	8.53
		Canada	8.53
		United States	8.53
Jet/kerosene	7.88	OECD Pacific	7.93
		Canada	7.93
		United States	7.93
Other kerosene	7.88	OECD Pacific	7.74
		Canada	7.74
		United States	7.74
Gas/diesel	7.46		
Residual fuel oil	6.45	OECD Pacific	6.66
		Canada	6.66
		Mexico	6.43
		United States	6.66
Petroleum coke	5.5		
Other products	ranging from 6.17 to 8.0		

Natural gas data collected from IEA member countries are reported in both energy units (terajoule) and volume units (million cubic metres) using standard conditions (i.e. at 15 degrees Celsius and 760 mm Hg). Data are reported using gross calorific value.

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Conversion factors from mass or volume to heat
(Gross calorific value)

	LNG**		GAS							
			Norway		Netherlands		Russia		Algeria	
To:	MJ	Btu	MJ	Btu	MJ	Btu	MJ	Btu	MJ	Btu
From:	multiply by:									
cm*	40.00	37660	40.00	37913	33.32	31581	38.23	36235	39.19	37145
Kg	54.25	51417	52.22	49495	42.07	39875	55.25	52363	52.46	49726

* At 15°C.
** In gaseous state – average OECD imports.

Conversion factors for natural gas

Scm versus Ncm

To:	Standard cm	Normal cm
From:	multiply by:	
Standard cm*	1	0.948
Normal cm**	1.055	1

*1 Scm measured at 15°C and 760mm Hg.
**1 Ncm measured at 0°C and 760 mm Hg.

LNG versus GAS

To:	Metric ton of LNG	cm of LNG	Standard cm*
From:	multiply by:		
Metric ton of LNG	1	2.22	1360
cm of LNG	0.45	1	615
Standard cm*	$7.35*10^{-4}$	$1.626*10^{-3}$	1

*1 Scm = 40 MJ.

Gross versus net calorific value

1 NCV* = 0.9 GCV**

*NCV = Net Calorific Value.
**GCV = Gross Calorific Value.

Conversion factors for natural gas flow rates (*)

To:	Bcm per year	Million tonnes per year	Bcf per day	Tcf per year	PJ per year	TWh per year	MBtu per year	Mtoe per year
From:	multiply by:							
Bcm per year	1	0.7350	0.09681	0.03534	40.00	11.11	3.79×10^{7}	0.9554
Million tonnes per year	1,360	1	0.1317	0.04808	54.40	15.11	5.16×10^{7}	1.299
Bcf per day	10.33	7.595	1	0.3650	413.2	114.8	3.91×10^{8}	9.869
Tcf per year	28.30	20.81	2.740	1	1,132	314.5	1.07×10^{9}	27.04
PJ per year	0.02500	0.01838	0.002420	0.0008834	1	0.2778	9.47×10^{5}	0.02388
TWh per year	0.09000	0.06615	0.008713	0.003180	3.600	1	3.41×10^{6}	0.08598
MBtu per year	2.638×10^{-8}	1.939×10^{-8}	2.554×10^{-9}	9.32×10^{-10}	1.055×10^{-6}	2.93×10^{-7}	1	2.520×10^{-8}
Mtoe per year	1.047	0.7693	0.1013	0.03698	41.87	11.63	3.97×10^{7}	1

(*) based on gas with calorific value of 40 MJ/cm.

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IEA methodology for calculating minimum oil stockholding obligation and compliance

The IEA minimum stockholding obligation is based on the average daily net imports of the previous calendar year. This covers all petroleum, including both primary products (such as crude oil and NGLs) and refined products, with the exception of naphtha and volumes of oil used for international marine bunkers. Refined products are converted to *crude oil equivalent*, the amount of crude necessary to produce a given amount of product.

A country's 90-day emergency reserve commitment is defined as: daily net imports x 90.

Daily net imports are defined as:

- net imports (adjusted for stock changes)[1] of crude oil, NGL and feedstocks, from which is deducted a naphtha yield of 4%[2]
- plus net imports (adjusted for stock changes) of all oil products (excluding naphtha and international marine bunkers) converted to crude oil equivalent by multiplying by a factor of 1.065
- divided by the number of days in the year.

A country's emergency reserves, which are counted towards meeting its 90-day commitment, are defined as its total oil stocks (net any bilateral stockholding arrangements), adjusted in the following way:

- a naphtha yield of 4% is deducted from stocks of crude oil, NGL and feedstocks
- oil product stocks (with the exception of stocks of petrochemical naphtha and of international marine bunkers) could be counted as emergency reserves in either of the following ways:
  - all existing product stocks, converted to crude oil equivalent by the general IEA factor of 1.065
  - only stocks of the three main product groups (gasolines and naphtha for gasoline production, middle distillates and heavy fuel oil) which are converted to crude oil equivalent by an average factor of 1.2[3]
- a 10% deduction is made in order to account for unavailable stocks (such as tank bottoms).

Days of net import cover is the result of: emergency reserves ÷ daily net imports.

1. Net imports are adjusted for stock change such that increases of stocks in a given year are not counted as part of the daily net imports amount, while stock reductions in a given year are added to the daily net import figure. Thus, oil imported for the purpose of building emergency reserves does not add to the emergency reserve commitment.
2. For most IEA countries, a 4% deduction is made to reflect a naphtha yield, based on a weighted average across the IEA. Countries for which the national yield is above 7% may opt to use their actual national naphtha yield factors or volume to adjust their net imports.
3. This factor is used to convert an aggregate of the three main products into an amount of crude oil required in average refinery operations to produce those products. The use of this factor assumes that products, other than the three main products and naphtha, are stocked in proportion to their refinery yield.

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Summary of EU legislation on stocks of crude oil and petroleum products

The European Union adopted a new oil stockholding Directive in September 2009 (Council Directive 2009/119/EC), which brought the EU system closer in line with that of the IEA[1].

Main provisions concerning emergency stocks

Member States must maintain a total level of oil stocks corresponding, at the very least, to 90 days of average daily net imports or 61 days of average daily inland consumption, whichever of the two quantities is greater.

EU member states have an obligation to ensure that stocks are available and physically accessible. In this regard, they are responsible for putting in place arrangements for the identification, accounting and control of these stocks. A register containing information on emergency stocks (the location of the depot, refinery or storage facility, the quantities involved, the owner of the stocks and their nature) should be established and continually updated. A summary copy of the register shall be sent to the European Commission once a year.

In order to maintain stocks, each member state may set up a **central stockholding entity (CSE)** in the Community, in the form of a non-profit making body or service. The CSE shall maintain oil stocks (including acquisition and management of these stocks). Under the conditions and limitations laid down by the Directive, CSEs and member states may delegate part of the management of stocks to another member state with stocks on its territory, to the CSE set up by the said member state or to economic operators.

Under the conditions and limitations laid down by the Directive, member states may authorise any economic operators upon whom they have imposed stockholding obligations to delegate part of these obligations to:

- the CSE of the member state in question
- one or several CSEs that have expressed a wish to maintain such stocks
- certain other economic operators which have surplus stocks.

Main provisions relating to specific stocks and other stocks of products

Each member state is invited to commit to maintaining specific stocks. In this case, they must maintain a minimum level defined in terms of number of days of consumption. Specific stocks shall be owned by the member state concerned or the CSE set up by it. member states shall publish their decision to hold specific stocks in the Official Journal of the European Union.

1. The following text uses excerpts from http://europa.eu/legislation_summaries/energy/external_dimension_enlargement/en0006_en.htm#key.

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Specific stocks shall be composed of one or several of the following products:

▪ ethane	▪ LPG
▪ motor gasoline	▪ aviation gasoline
▪ gasoline-type jet fuel (naphtha-type jet fuel or JP4)	▪ kerosene-type jet fuel
▪ other kerosene	▪ gas/diesel oil (distillate fuel oil)
▪ fuel oil (high and low sulphur content)	▪ white spirit and SBP
▪ lubricants	▪ bitumen
▪ paraffin waxes	▪ petroleum coke

Member states shall ensure that in total, for the reference year, the crude oil equivalent of the quantities consumed of products included in the categories used is at least equal to 75 % of inland consumption. If there is no commitment to maintain at least 30 days of specific stocks, member states shall ensure that at least one-third of their commitment is held in the form of products, under the conditions laid down by the Directive.

Possible differences between the EU and the IEA days coverage of stocks

While the 2009 Directive brings greater alignment between the IEA and EU systems, there remain differences such that a country's level of compliance can be different under the two systems.

Such differences would not come from using different calculations, as the EU Directive adopts the same methodology as that which the IEA uses (see IEA Methodology for Calculating Minimum Oil Stockholding Obligation and Compliance described above). Thus, for example, both systems will make the same adjustment for naphtha and the same 10% deduction for unavailable stocks. Instead, differences would come primarily from a narrower definition under the Directive for the stocks which are counted towards meeting the stockholding obligation.

The IEA methodology counts all oil stocks in a country (net bilateral stockholdings). This includes stocks held by industry purely for commercial or operational purposes. Under the EU Directive, only the "emergency stocks" (stocks meeting certain requirements with respect to availability, defined under article 5 and 12(3) of the Directive) count towards meeting the minimum obligation. Thus the EU system will not count stocks held by industry participants for reasons other than meeting a national stockholding obligation (either directly or based on a delegation from another obligated industry participant).

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The legal basis for emergency response organisations, stockholding and the implementation of stockdraw and other emergency measures

	Legislation	Powers
Australia	**A. Oil emergency response organisations**	
	The Liquid Fuel Emergency Act of 1984, as amended in 2007.	The Act provides a comprehensive national approach to manage a severe fuel shortage.
	B. Oil stockholding	
	The Liquid Fuel Emergency Act of 1984, as amended in 2007.	Minister(s) may specify quantity, locations and period of duration of reserves.
	C. Implementation of oil stockdraw and other oil emergency response measures	
	The Liquid Fuel Emergency Act of 1984, as amended in 2007. Section 12-15.	The Australian government could require maintenance of stocks, stockdraw, the physical transfer, the sale of liquid fuels to designated customers and the regulation of refinery operations.
	2006 Offshore Petroleum and Greenhouse Gas Storage Act 2006.	The Act has a provision for the Australian government to be able to direct petroleum producers to take all necessary and practical steps to increase or reduce the rate at which oil is being recovered within a licensed area or pool.
	D. Natural gas emergency response organisations and measures	
	Natural Gas Law 2008.	The Act provides the legal framework for natural gas regulation at the national level. However, the management of natural gas supply disruptions generally takes place at state or territory level – with emergency powers for managing natural gas supply disruptions conferred by state or territory level legislation. In the event of a large disruption affecting more than one jurisdiction, the National Gas Emergency Response Protocol (set out in a 2005 MOU between all the states and territories and the commonwealth government) provides guidance to gas suppliers, gas retailers, the natural gas market operator, and state and territory jurisdictions on their roles and responsibilities during natural gas supply disruptions.
Austria	**A. Oil emergency response organisations**	
	Oil stockholding Act 2012 - Federal Act on the Holding of Minimum Reserves of Crude Oil and Petroleum Products.	These laws provide the legal framework for Austrian emergency management.
	B. Oil stockholding	
	Oil stockholding Act 2012 - Federal Act on the Holding of Minimum Reserves of Crude Oil and Petroleum Products.	The law obliges all importers of crude oil and oil products to maintain emergency reserves equal to 25 % of the previous year's net imports, plus 10% for unavailable stocks.
	C. Implementation of oil stockdraw and other oil emergency response measures	
	Energy Intervention Powers Act 2012 - Federal Act on Intervention Measures to Safeguard Energy Supplies.	The law provides for the Minister for Economic Affairs to determine by ordinance a certain percentage for stock drawdown.
	D. Natural gas emergency response organisations and measures	
	Energy Intervention Powers Act 2012 - Federal Act on Intervention Measures to Safeguard Energy Supplies.	The law provides for the Minister of Economy, Family and Youth to determine by order interventions measures.
		E-Control (the Austrian national regulatory authority) is in charge of the preparation of the measures and – if they are taken in case of an emergency – of their co-ordination.

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	Legislation	Powers
Belgium	**A. Oil emergency response organisations**	
	Royal Decree of 11th October 1984 (MB 27th November 1984).	The Decree provides powers to create the National Oil Board, the single body responsible for oil crisis management, to implement IEA emergency measures and function as NESO.
	B. Oil stockholding	
	Act of 26th January 2006. (Act on the compulsory stockholding of oil and petroleum products and on the setting up of an agency responsible for managing part of these stocks, amending the Act of 10 June 1997 on the general arrangements for the holding, movement and control of excisable products).	The Act establishes the public limited company, APETRA, responsible for holding and managing the compulsory stocks of oil and petroleum products.
		APETRA is mandated to take over the country's stockholding obligation from refiners and importers, starting with 75 days coverage in 2007 and reaching full coverage of the obliged emergency stocks within five years.
	C. Implementation of oil stockdraw and other oil emergency response measures	
	Act of 26th January 2006.	The Act gives the power to the Minister of Economic Affairs to order the release of compulsory oil stocks.
Canada	**A. Oil emergency response organisations**	
	The Energy Supplies Emergency Act of 1978/79 as amended in 2012.	The Act provides the primary basis for the Canadian Federal Government to respond to oil emergencies.
		Under the Act is established the Energy Supplies Allocations Board (ESAB) which has the necessary powers to impose demand restraint, allocate crude oil and products, and ration gasoline and diesel fuel in an IEP collective action or national emergency.
	The Emergencies Act of 1988.	The Act provides short-term statutory power to deal with and establish planning and preparedness programmes for different national emergencies.
	B. Oil stockholding	
	(No compulsory stockholding legislation exists. As a net exporter, Canada is not obliged to hold emergency stocks under the IEP).	
	C. Implementation of oil stockdraw and other oil emergency response measures	
	The Energy Supplies Emergency Act of 1978/79 as amended in 2012.	In a declared national emergency, the Act gives the power to the ESAB to regulate stock building, storage, disposal of stocks and export. ESAB would have the authority to set prices.
	D. Natural gas emergency response organisations and measures	
	The Emergencies Act of 1988.	The Act provides short-term statutory power to deal with and establish planning and preparedness programmes for different national emergencies.
Czech Republic	**A. Oil emergency response organisations**	
	The Act № 189/1999 on Emergency Oil Stocks as amended in 2004 and in 2013. The Act № 97/1993 on the Competence of the Administration of State Material Reserves as amended in 1996, in 1999, in 2000 and in 2004.	The Administration of the State Material Reserves (ASMR) is the core of NESO.
	B. Oil stockholding	
	The Act № 189/1999 on Emergency Oil Stocks as amended in 2004 and in 2013.	The Act specifies that ASMR stocks must be no less than 90 days of net imports, meeting IEA and EU stockholding requirements.
	C. Implementation of oil stockdraw and other oil emergency response measures	
	The Act № 97/1993 on the Competence of the Administration of State Material Reserves as amended in 1996, in 1999, in 2000 and in 2004.	These Acts empower the ASMR to release the state-owned stocks and to control company stocks in time of emergency.
	D. Natural gas emergency response organisations and measures	
	Decree no. 334/2009 Coll. On States of Emergency in the Gas Sector.	The Decree establishes measures for states of emergency and their prevention, procedures and contingency plans.

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	Legislation	Powers
Denmark	**A. Oil emergency response organisations**	
	The Oil Emergency Preparedness Act № 354/2012. The Act № 165/1975 on the Information and Selling Obligations regarding hydrocarbons.	These Acts provide the Minister of Transport and Energy with powers to establish a NESO, administer an oil emergency, require oil companies to sell crude oil and products in fulfilment of international allocation commitments.
	B. Oil stockholding	
	The Oil Emergency Preparedness Act № 354/2012. Executive Order of 8 November 2013 about Compulsory Stockholding Obligations.	No stockholding legislation exists under the IEP as Denmark is a net exporter. Denmark is obliged to hold stocks equivalent to 61 days of the previous years' consumption under EU Directive 2009/119/EC. Denmark voluntarily increases its EU obligation to hold a surplus of 20%, i.e. 73.2 days of consumption. The Act and the Order implement the EU Oil Stocks Directive 2009/119/EC and impose an obligation on companies to hold emergency stocks.
	C. Implementation of oil stockdraw and other oil emergency response measures	
	The Consolidated Act № 88/1986 on the Supply Measures.	The Act empowers the Minister of Transport and Energy to establish provisions regarding the use, distribution, price equalisation, and physical placing of stocks.
Finland	**A. Oil emergency response organisations**	
	The Act № 1682/1991 on the Adaptation of Certain Provisions in the International Energy Program and its application.	The Act provides the Council of State with wide-ranging powers to meet IEP requirements. This includes the necessary power to establish a NESO within the Ministry of Trade and Industry.
	The Act № 1390/1992 on the Security of Supply.	The Act provides the legal basis for co-operation between National Emergency Supply Agency (NESA) and the industry.
	B. Oil stockholding	
	The Act № 1390/1992 on the Security of Supply.	Under the Act, State-owned stocks are held by the NESA.
	The Act № 1070/1994 on the Compulsory Stockholding of Imported Fuels.	Oil importers are required to maintain compulsory oil stocks corresponding to two months' imports based on the average of the previous year
	C. Implementation of oil stockdraw and other oil emergency response measures	
	The Act № 1390/1992 on the Security of Supply.	The Act provides the government with the statutory power in case of emergency to release public stocks. It also provides legal basis for other measures such as rationing.
	The Act № 1070/1994 on the Compulsory Stockholding of Imported Fuels.	Under the Act, the NESA may, upon request, authorise industry holders of compulsory stocks to use their obligated stocks.
	D. Natural gas emergency response organisations and measures	
	The Act № 1070/1994 on the Compulsory Stockholding of Imported Fuels.	The Act sets the standard of gas supply security for suppliers. Gas importers and plants are required to hold alternative fuel stocks corresponding to three month's natural gas import. Municipal users consuming over 15 mcm of natural gas per year are also obliged to hold alternative stocks corresponding to three months of consumption.

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	Legislation	Powers
France	**A. Oil emergency response organisations**	
	The Code of Energy.	The Code is the legal basis for emergency policy and allows the Administration to meet its obligations under the IEP.
	B. Oil stockholding	
	The Code of Energy 1993 Order concerning the creation of strategic oil stocks in France.	The Code and the Order define the obligation to hold emergency stocks for all operators. All industry operators are required to hold the equivalent of 29.5% of the volume of oil released for domestic consumption during the previous calendar year.
	C. Implementation of oil stockdraw and other oil emergency response measures	
	The Code of Energy The Governmental Order of 1959 on the Organisation of National Defence The Law on the Oil Regime in 1992 and its Implementing Decrees and Orders.	These Laws, Decrees and Orders provide the Administration with the legal basis for taking actions to improve emergency preparedness, and to implement measures during a supply disruption.
	D. Natural gas emergency response organisations and measures	
	The Code of Energy (Art. L421-4). The Order on National Emergency Measures Decree No. 2004-2512 on public service obligations in the gas sector. Decree No. 2006-10343 on access to underground storage of natural gas.	The Order and the Decrees set the standard for natural gas supply disruptions together with the National Contingency Plan.
Germany	**A. Oil emergency response organisations**	
	Energy Security of Supply Act 1975.	The law provides the basis for the voluntarily creation of the German NESO as a co-operative body of government, industry and the German Stockpiling Agency EBV.
	B. Oil stockholding	
	Oil Stockholding Act 2012 (Section 3).	The law stipulates that the EBV shall constantly maintain stocks of oil and petroleum products at a level which corresponds to a minimum of 90 days of net imports.
	C. Implementation of oil stockdraw and other oil emergency response measures	
	The Oil Stockholding Act 2012 and the Energy Security of Supply Act 1975.	The actual release of emergency stocks is authorised under the Oil Stockholding Act by means of an ordinance issued by the Federal Ministry of Economics and Technology (BMWi). Decisions on the release of stocks from EBV are prepared in the Director General for Energy Policy's department in BMWi, and taken by the Federal Minister of Economics and Technology.
		When stocks are released, the BMWi activates the National Emergency Strategy Organisation (NESO) and consults the NESO's Crisis Supply Council (KVR) on issues of implementation, such as the breakdown of the quantity released between crude oil and the individual products.
		The legal basis for demand restraint measures in Germany and for various other interventions in the oil market is the Energy Security of Supply Act. A declaration by the Federal Government that the energy supply is endangered or has been disrupted is normally required before demand restraint measures can be implemented. However, if the measures are being implemented to meet Germany's obligations under the International Energy Program (IEP), a government declaration is not required.
	D. Natural gas emergency response organisations and measures	
	Energy Security of Supply Act 1975.	In an emergency the Federal Government has the responsibility of triggering Germany's natural gas emergency response measures by declaring a state of emergency. Once an emergency has been declared, the Energy Security of Supply Act permits the enactment of Ordinances to ensure that vital energy needs are met. Ordinances can restrict the sale, purchase or use of goods, both in terms of quantity and time, or permit them only for certain priority purposes. A key example is the Ordinance to Ensure the Supply of Gas in a Supply Crisis, which regulates the responsibilities for load distribution in the natural gas network. It permits the bodies responsible for load distribution – the Federal Network Agency and the various Lander – to issue instructions to companies and consumers.

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	Legislation	Powers
Greece	**A. Oil emergency response organisations**	
	The Law № 4123/2013 on the maintaining of a minimum level of oil stocks.	The Law and the Ministerial Decisions are the legal framework for the Greek NESO operation, including establishment of the Severe Oil Disruptions Committee.
	The Ministerial Decision D1/B/10051 for the designation of Crisis Committee's members.	
	The Emergency Plan according to the Law 4123/2013 (Ministerial Council's Act 27).	
	B. Oil stockholding	
	The Law № 4123/2013 on the maintaining of a minimum level of oil stocks. The Regulation D1/12565/2007 for maintaining safety stocks.	The Law 4123/2013 (Official Gazette A' 43-19.02.2013) covers EU council Directive 2009/119EC of 14 September 2009 imposing on EU Member States to maintain a minimum stock of crude oil and/or products. This includes a provision for the establishment of a new stockholding agency, a choice of keeping a percentage of up to 30% of stocks within the territory of other EU Member States, and provisions for stricter fines in case of non-compliance and stricter rules for data reporting.
	C. Implementation of oil stockdraw and other oil emergency response measures	
	The Law № 4123/2013 on the maintaining of a minimum level of oil stocks.	The legal framework provides the Minister for Environment, Energy and Climate Change with the statutory power to control and drawdown emergency reserves held by industry.
	The Emergency Plan according to the Law 4123/2013 (Ministerial Council's Act 27).	The Emergency Plan and the relative Ministerial Decision form the legal basis for measures that the Severe Oil Disruptions Management Committee may decide to undertake in order to tackle a contingent oil disruption.
	D. Natural gas emergency response organisations and measures	
	The Law № 4001/2011 on the Liberalisation of the Natural Gas Markets.	The Law sets the regulatory framework of the natural gas market in Greece. The Law also transposed into the Greek legislation the EU Directive s 2009/72/EC and 2009/73/EC.
	Preventive action plan for enhancing gas supply security in the Greek National Natural Gas System (NNGS)-March 2013-According to the provisions of articles 4 and 5 of Regulation 994/2010 concerning measures to safeguard gas supply security and repealing Council Directive 2004/67/EC.	The preventive action plan aims to provide the most suitable path towards fulfilling the risk criteria set out in the Risk Assessment, as well as the infrastructure and supply standards of the Regulation (994/2010).
	National Regulatory Authority's decision No 122/2013 regarding the approval of the National Emergency Plan according to the provisions of Regulation (EU) 994/2010 of the European Parliament and the Council of October 2010, as forwarded to the Official Gazette for publication.	The National Emergency Plan among others : (a) defines the role and responsibilities of natural gas undertakings and of industrial gas customers (b) defines the role and responsibilities of the Competent Authorities (c) ensures that natural gas undertakings and industrial gas customers are given sufficient opportunity to respond at each crisis level (d) establishes detailed procedures and measures to be followed for each crisis level (e) designates a crisis manager or team and define its role (f) identifies the contribution of market-based measures for coping with the situation at alert level and mitigating the situation at emergency level (g) identifies the contribution of non-market-based measures.

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	Legislation	Powers
Hungary	**A. Oil emergency response organisations**	
	The Law IL of 1993 on the Security Stockpiles of Imported Petroleum and Petroleum Products as amended in 1997, 2004 and 2010.	The Law provides for the establishment and operation of a NESO under the supervision of the Ministry of Economy and Transport.
	B. Oil stockholding	
	The Law IL of 1993 on the Security Stockpiles of Imported Petroleum and Petroleum Products as amended in 1997, 2004 and 2010.	The Hungarian Hydrocarbon Stockpiling Association (MSZKSZ or HUSA) maintains, on behalf of member companies, stock levels no less than 90 days of domestic consumption of the three main product categories (gasoline, middle distillates and fuel oil).
	C. Implementation of oil stockdraw and other oil emergency response measures	
	The Law IL of 1993 on the Security Stockpiles of Imported Petroleum and Petroleum Products as amended in 1997, 2004 and 2010.	The Law provides the Ministry of Economy and Transport with the statutory power to order the release of the security stockpiles in case of energy supply crises and when the EU or the IEA declares emergency measures.
	D. Natural gas emergency response organisations and measures	
	Act No. XXVI, 2006 on Safety Stockpiling of Natural Gas.	This law establishes the strategic gas stocks.
	Government Decree No. 265 / 2009.	The Decree outlines demand restrictions that can be implemented in case of supply disruption, when there are no other applicable means for ensuring the balance in the system.
Ireland	**A. Oil emergency response organisations**	
	The Fuels (Control of Supplies) Acts of 1971 and 1982.	These Acts provide the Minister for Communications, Energy and Natural Resources with the statutory power to deal with emergency measures for crisis in the oil supply.
	B. Oil stockholding	
	The National Oil Reserves Agency Act 2007.	This legislation provides the basis for the National Oil Reserve Agency and for Ireland's strategic oil stockholding in compliance with EU /IEA requirements.
	Statutory Instrument 541 of 2012 – European Union (Oil Reserves) Regulations 2012.	
	Statutory Instrument 567 of 2007- National Oil Reserves Agency 2007 (Returns and Levy) Regulations 2007.	
	C. Implementation of oil stockdraw and other oil emergency response measures	
	The Fuels (Control of Supplies) Acts of 1971 and 1982. The National Oil Reserves Agency (NORA) Act 2007.	Implementation of oil stockdraw and other oil emergency response measures are provided for in the NORA Act and in the Fuels (Control of Supplies) Acts.
	D. Natural gas emergency response organisations and measures	
	Statutory Instrument 697: European Communities (Security of Natural Gas Supply) Regulations 2007.	These Regulations give legal effect to Directive 2004/67/EC concerning measures to safeguard security of natural gas supply. The Regulations amend the Gas (Interim) (Regulation) Act 2002 (No. 10 of 2002) and set out, inter alia, the duties of licence holders in connection with a gas emergency, the information required in the annual Gas Capacity Statement and the functions of the Commission for Energy Regulation with regard to the protection of security of natural gas supply. It also provides for the appointment, by the Commission for Energy Regulation, of a National Gas Emergency Manager and the drawing up of a Natural Gas Emergency Plan.
	Statutory Instrument 336: European Union (Security of Natural Gas Supply) Regulations 2013.	These Regulations give legal effect to Regulation (EU) No. 994/2010 concerning measures to safeguard security of gas supply The Regulations designate and set out the functions of the Commission for Energy Regulation as Competent Authority, whose key role is to ensure compliance with and implementation of the measures set out in EU Regulation 994/2010. The functions of the Competent Authority include, inter alia, the appointment of Authorised Officers to assist in the response to and management of a gas supply emergency. The Regulations also make an amendment to the Gas (Interim) (Regulation) Act 2002, as amended by SI 697/2007. The amendment refers to the term 'protected customer' and seeks to revise this term in line with the definition/use of the term in these Regulations and EU Regulation 994/2010.

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	Legislation	Powers
Italy	**A. Oil emergency response organisations**	
	The Legislative Decree №. 249 of 31 December 2012.; Official Journal: Gazzetta Ufficiale della Repubblica Italiana, number: 22, Publication date: 26/01/2013.	The Decree provides the Ministry of Economic Development with the statutory power to deal with emergency measures for crisis in the oil supply.
	B. Oil stockholding	
	Ministerial Decree of April 19th 2013 on the adoption of Preventive action plan and of Emergency plan.	The Decree establishes the legal basis for stockholding obligations on industry. Ministry of Economic Development establishes on a yearly basis the total oil stock amount to be held for the country overall, in accordance with the obligations of the European Commission and the IEA. The total amount of stock holding obligations is distributed proportionally among the various companies present on the market on the basis of the amounts of products sold in the previous year.
	C. Implementation of oil stockdraw and other oil emergency response measures	
	Ministerial Decree of September 13th 2013 on the amendment on the Emergency plan.	The Decree provides the Ministry of Economic Development with the statutory power to use and remove the reserve stocks in case of difficulties of supply and when the EU or the IEA declares emergency measures.
	D. Natural gas emergency response organisations and measures	
	Ministerial Decree of September 13th 2013 on fuel switching of gas fired power plants.	
Japan	**A. Oil emergency response organisations**	
	The Establishment Law of the Ministry of Economy, Trade and Industry.	The Law provides wide powers including the ability to establish a NESO in the Agency of National Resources and Energy.
	B. Oil stockholding	
	The Oil Stockpiling Law of 96/1975 (last amended in 2012).	The Law obliges industry to hold from 70 days to 90 days of oil import, sale or refined production based on the average of previous 12 months. The Law also allows the METI to delegate the management of government stocks to JOGMEC.
	Japan Oil, Gas and Metals National Corporation Law of 94/2002 (last amended in 2011).	In 1978 the government initiated its national stockpiling programme through JOGMEC (formally JNOC), which maintains 50 million kl of the government stocks, all of which are crude oil.
	C. Implementation of oil stockdraw and other oil emergency response measures	
	The Oil Stockpiling Law of 96/1975 (last amended in 2012).	The Law gives the power to the Minister of Economy, Trade and Industry to lower the whole obligation in case of global oil disruptions as well as of local shortages due to natural disasters. The law also gives the Ministry the legal power to release the government stocks not only in global oil supply disruption but also in local supply disruptions because of natural disasters.
	The Petroleum Supply and Demand Adjustment Law of 122/1973 (last amended in 2012).	The Law gives the Council of Ministers the authority to implement demand restraint measures including allocation.
	D. Natural gas emergency response organisations and measures	
	The Gas Business Act of 1954 (last amended in 2011).	This sets the standards for market activities for natural gas, including obligation on gas utilities to submit gas supply plan to the METI every fiscal year.

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	Legislation	Powers
Republic of Korea	**A. Oil emergency response organisations**	
	The Petroleum and Petroleum-Alternative Fuel Business Act (last amended in 2005). The Basic Energy Act.	These Acts provide the Ministry of Trade, Industry and Energy (MOTIE) with the statutory power to deal with emergency measures for crisis in the oil supply.
	B. Oil stockholding	
	The Petroleum and Petroleum-Alternative Fuel Business Act (last amended in 2005).	The Act obliges major oil refiners, oil marketers and oil importers to maintain emergency stocks at the level which the MOTIE requires.
	The Korea National Oil Corporation Act (last amended in 1998).	The Act requires KNOC to maintain national stockpiling on behalf of the government.
	C. Implementation of oil stockdraw and other oil emergency response measures	
	The Petroleum and Petroleum-Alternative Fuel Business Act (last amended in 2005). The Basic Energy Act. The Energy Use Rationalisation Act.	The Minister of MOTIE has the authority to make an energy demand and supply plan in case of an energy crisis and can decide on emergency response measures, including oil release, reduction of the level of private compulsory oil stock and demand restraint.
	D. Natural gas emergency response organisations and measures	
	There is no clear legal basis for emergency planning and managing crisis situations that affect the natural gas system in Korea.	
Luxembourg	**A. Oil emergency response organisations**	
	The Law of 22nd September 1982 on Oil Supply in Case of Emergency.	The Law provides for the constitution of the NESO under the authority of the Minister for Economic Affairs and Foreign Trade.
	B. Oil stockholding	
	The Decree of 31st October 1973.	The Decree defines a compulsory stock level of oil products for all oil importers as 90 days of the previous year's consumption.
	C. Implementation of oil stockdraw and other oil emergency response measures	
	The Law of 22nd of September 1982 and 8th December 1981 amended in 1991.	The Law gives the government the legal authority to take decisions on emergency sharing, including stockdraw, if oil product supply is endangered.
	D. Natural gas emergency response organisations and measures	
	Law on the Organisation of the Natural Gas Market of 1 August 2007.	The Law stipulates the country's natural gas supply security measures and guidelines for companies operating on its domestic gas market.
Netherlands	**A. Oil emergency response organisations**	
	The Oil Stockholding Act of 2012.	The Act provides the Ministry of Economic Affairs with the statutory power to deal with emergency measures for crisis in the oil supply. The NESO is part of his ministry.
	B. Oil stockholding	
	The Oil Stockholding Act of 2012.	The Act implements the European Union Oil Stocks Directive 2009/119/EC and stipulates a legal obligation for The Netherlands to hold 100 days of net imports. Companies which sell more than 100 000 tonnes (the threshold) of oil products to the inland market are obliged to hold 12% of volumes sold above this threshold. The public stockholding agency COVA is responsible for holding the balance between the industry obligations and the national commitment towards the IEA.
	C. Implementation of oil stockdraw and other oil emergency response measures	
	The Oil Stockholding Act of 2012.	The Act gives the Minister of Economic Affairs the power to instruct COVA and companies to draw down their compulsory stocks.
	D. Natural gas emergency response organisations and measures	
	The 2004 Gas Act.	The Act establishes responsibilities related to gas crises.

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	Legislation	Powers
New Zealand	**A. Oil emergency response organisations**	
	The International Energy Agreement Act of 1976; The Petroleum Demand Restraint Act of 1981: The Petroleum Demand Restraint (Regulations Validation and Revocation) Act of 1981.	These Acts provides the Ministry of Business, Innovation and Employment (MBIE) with powers to implement all obligations of New Zealand under the IEP including the setting up of a NESO.
	B. Oil stockholding	
	The International Energy Agreement Act of 1976.	The Act stipulates that the MBIE has the authority to order the maintenance of stocks by oil producers, refiners and importers at a level required by the IEP.
	C. Implementation of oil stockdraw and other oil emergency response measures	
	The Petroleum Demand Restraint Act of 1976.	The Act provides for regulations on stock drawdown and to impose restrictive demand restraint measure.
	D. Natural gas emergency response organisations and measures	
	Gas Governance (Critical Contingency Management) Regulations 2008.	The Regulations set the framework within which New Zealand gas emergencies are managed
Poland	**A. Oil emergency response organisations**	
	The Act of 16th February 2007.	Act on stocks of crude oil, petroleum products and natural gas, the principles of proceeding in circumstances of a threat to the fuel security of the State and disruption on the petroleum market. This is the legal basis for Poland's oil crisis management.
	Decree No 71 of 11 May 2006.	The Decree establishes the statutes of the NESO.
	B. Oil stockholding	
	The Act of 16th February 2007.	The Act gives the Material Reserves Agency (ARM) the responsibility of managing public oil reserves and monitoring the stockholding obligation on industry.
		The Act requires the ARM to hold no less than 14 days of net imports.
		The Act provides statutory powers over all industry stocks, and obliges all liquid fuel producers and importers to hold minimum stock levels based on their production or imports from the previous calendar year. The minimum obligation rises from 66 days at end 2006 to 73 days at the end of 2007 and 76 days at the end of 2008. Additionally, producers and imports of LPG have an obligation which will be progressively increased from 3 days cover by end 2007 to 30 days by end 2011. This obligation may be met by holding the volumes of motor gasoline which equal the calorific value of the LPG obligation.
	C. Implementation of oil stockdraw and other oil emergency response measures	
	The Act of 16th February 2007.	The Act provides the Minister of Economy with the statutory power to release both industry and state oil reserves. Industry stocks would be made available either through the relaxation of minimum stockholding obligations or by directing industry to make compulsory stock draws.
		The Act provides legal authority to implement demand restraint measures. Specific measures are stipulated in articles 40 and 41 of the Act.
	D. Natural gas emergency response organisations and measures	
	Act of 16 February 2007 (amended in 2011).	The Act obligates energy enterprises running a business of international gas trading and importers to maintain compulsory gas stocks.

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	Legislation	Powers
Portugal	**A. Oil emergency response organisations**	
	Decree Law № 114/2001 on the Crisis situation and response measures.	These Laws provide the government with powers to set up a NESO, in which the Directorate General of Energy and Geology (DGEG) has the leading role.
	Decree Law № 10/2001 on the Petroleum Reserves (last amended in 2004).	
	Decree Law № 31/2006 on new framework law of the petroleum sector.	
	B. Oil stockholding	
	Decree Law № 10/2001 on the Petroleum Reserves (last amended in 2004).	Under the Law, oil industry operators are obliged to hold two-thirds of the EU obligation (i.e. 60 days of consumption of gasoline, distillates and fueloil). The Law also sets the legal framework for a stockholding agency (EGREP), which has to hold the balance between the industry obligations and the national commitment towards the IEA based on net imports.
	C. Implementation of oil stockdraw and other oil emergency response measures	
	Decree Law № 114/2001 on the Crisis situation and response measures.	These Laws provides the Minister responsible for energy with the statutory power to order a drawdown of industry and agency reserves.
	Decree Law № 10/2001 on the Petroleum Reserves (last amended in 2004).	The Law on the Crisis situation and response measures also provides the legal basis to take demand restraint measures.
	D. Natural gas emergency response organisations and measures	
	Decree Law № 30/2006 amended in accordance with Decree Law № 230/2012.	The Decree law 140/2006 authorises the Minister responsible for energy to define priority rules, taking into consideration the supply of household consumers, health services, safety services and other consumers highly dependent on gas.
	Decree Law № 140/2006 amended in accordance with Decree Law № 231/2012.	Mandatory gas reserves must be provided by market suppliers who import natural to the country. The minimum quantity of stocks of natural gas need to be more than the necessary level to ensure the consumption of protected consumers and to meet the consumption of non-interruptible power plants.
		Release of compulsory gas stocks is to be decided by the Minister responsible for energy. No automatic triggers exist under the legislation.
Slovak Republic	**A. Oil emergency response organisations**	
	The Act № 218/2013 Coll. on the Emergency Stocks of Crude Oil and Oil Products and on Managing Crude Oil Emergency and on Change and Amendment of some Acts.	The Act provides the government of the Slovak Republic with powers to set up a NESO, in which the Administration of State Material Reserves of the Slovak Republic (ASMR) has the leading role.
	Resolution of the Security Council of the Slovak Republic no. 109, Principles and Ways of Managing Crude Oil Emergency.	The Resolution outlines specific emergency procedures for oil supply disruptions.
	B. Oil stockholding	
	The Act № 218/2013 Coll.	The Act obliges the Emergency Oil Stocks Agency to hold stocks of crude oil or oil products corresponding at least to 90 days of average daily net imports during the previous calendar year.
	C. Implementation of oil stockdraw and other oil emergency response measures	
	The Act № 218/2013 Coll.	Under the Act, the ASMR would give a proposal for stock release to the government of the Slovak Republic in case of oil supply disruption.
		Article 14 (2) of the Act stipulates the demand restraint measures available to the government during an oil crisis.

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	Legislation	Powers
Sweden	**A. Oil emergency response organisations**	
	The Rationing Act (1978/268). The Oil Crisis Act (1975/197).	These Acts are the legal authority to establishing and operating the NESO. The Sustainable Energy Management team within the Swedish Energy Agency is its core.
	B. Oil stockholding	
	The Contingency Storage of Oil and Coal Act (1984/1049), as amended in 1995 and in 2002.	The Act obliges oil industry to hold stocks, corresponding to at least 25% of consumption or sales during the previous calendar year.
	C. Implementation of oil stockdraw and other oil emergency response measures	
	The Contingency Storage of Oil and Coal Act (1984/1049), as amended in 1995 and in 2002. The Agreement between the Swedish Energy Agency, Swedish Petroleum Institute and six major oil companies.	The Act and Agreement provide the government of Sweden with the statutory power to release the contingency stocks held by companies in crisis situations.
	D. Natural gas emergency response organisations and measures	
	The 2005 Natural Gas Act.	The Act gives powers to the system balancing authority to order system operators to increase or reduce the input or off-take of gas flows and to restrict or discontinue the transmission of natural gas to customers.
	The 2006 Natural Gas Ordinance.	The Ordinance establishes responsibilities under the Natural Gas Act
Switzerland	**A. Oil emergency response organisations**	
	The Federal Law of National Economic Supply of 8th October 1982 (last amended in 2001).	The Law and the Ordinances allow the setting up and operation of a NESO to implement IEP measures and respond flexibly to international oil disruptions.
	The Ordinance 531.11 of 6 July 1983 on Organisation of the National Economic Supply (last amended in 2003).	
	The Ordinance 531.12 of 2 July 2003 on preparation measures of the National Economic Supply.	
	B. Oil stockholding	
	The Federal Law of National Economic Supply of 8th October 1982 (last amended in 2001).	Under the Law and the Ordinances, all oil importers are obliged to hold at least 4.5 months of net imports of motor gasoline, diesel and heating oil, and 3 months for jet fuel.
	The Ordinance 531.211 of 6 July 1983 on the Main Principles of Stockholding (last amended in 2006).	
	The Ordinance 531.215.41 of 6 July 1983 on Establishing Compulsory Stocks on Fuel Oils and Transport Fuels (amended in 2011).	
	C. Implementation of oil stockdraw and other oil emergency response measures	
	The Federal Law of National Economic Supply of 8th October 1982 (last amended in 2001). The Ordinance of 8 September 2005 on Releasing Compulsory Stocks of Fuel Oils and Transport Fuels.	The Law and the Ordinance provide the government with the statutory power in case of emergency to order demand restraint actions and release of compulsory stocks.
	D. Natural gas emergency response organisations and measures	
	The Federal Law of National Economic Supply of 8th October 1982 (last amended in 2001). The Ordinance 531.215.42 of 8 September 2003 on Compulsory Stocks of Natural Gas.	The Law and the Ordinance set the standard of gas supply security for suppliers. All gas importers are requested to fulfil their obligation to hold natural gas stocks or heating oil stocks or to delegate the obligation to a third party.

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	Legislation	Powers
Turkey	**A. Oil emergency response organisations**	
	Petroleum Market Law (2003/5015).	The Law provides the government of Turkey with powers to set up the National Oil Stock Commission (NOSC; functions as the Turkish NESO), in which the Ministry of Energy and Natural Resources (MENR) has the leading role.
	B. Oil stockholding	
	Petroleum Market Law (2003/5015). LPG Market Law (2005/5307).	These Laws stipulate stockholding obligations for oil industry. Refineries and distributors are obliged to keep at least 20 days of product stocks based on the average daily sales of previous year. Eligible consumers that use more than 20 Kt on an annual basis are also obliged to hold 15 days' consumption of each type of liquid fuel in their consumption inventory.
	C. Implementation of oil stockdraw and other oil emergency response measures	
	Petroleum Market Law (2003/5015).	Petroleum Market Law requires a decision by the NOSC to drawdown compulsory industry stocks
	National Protection Law (1940/3780). Law on Organization and Duties of Headship of Disaster and Emergency Management (2009/5902).	The other Laws give the Council of Ministers the authority to implement emergency response measures other than oil stockdraw during a crisis.
	D. Natural gas emergency response organisations and measures	
	Natural Gas Market Law (2001/ 4646).	The Law sets the standards for market activities and security of supply for natural gas.
United Kingdom	**A. Oil emergency response organisations**	
	The Energy Act of 1976.	The Energy Act 1976 provides powers, subject to an Order in Council, for the Secretary of State for Energy and Climate Change to regulate or prohibit the production, supply, acquisition or use of fuel where there exists, or is imminent, an actual or threatened emergency in the UK affecting fuel supplies, or in order for the UK to meet its international obligations in the event of a reduction or threatened reduction in fuel supplies. These powers are the basis for the Department for Energy and Climate Change's authority to function as the UK NESO.
	B. Oil stockholding	
	The Energy Act of 1976.	The Act provides powers for the Secretary of State to direct "any person who…produces, supplies or uses crude liquid petroleum, or petroleum products" to hold stocks of such products based on "quantities… supplied…to the United Kingdom market in past periods".
	C. Implementation of oil stockdraw and other oil emergency response measures	
	The Energy Act of 1976.	The above powers allow the government to direct the drawdown of emergency stocks by companies, or take other measures.
	D. Natural gas emergency response organisations and measures	
	The Energy Act of 1976.	The Energy Act provides the legal authority for the operation of the National Emergency Plan for Gas and Electricity (NEP-G&E). The NEP-G&E sets out the arrangements between the gas and electricity industries, and DECC, for the safe and effective management of gas and electricity supply emergencies in Great Britain. The NEP-G&E includes provision for the use of emergency powers under the Energy Act, which would only be activated in significant emergencies.

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	Legislation	Powers
United States	**A. Oil emergency response organisations**	
	Executive Order 11912 as amended. The DOE Organization Act. The Energy Policy and Conservation Act (EPCA) as amended in 1990, 1992 and 1998, Sections 251-254.	The President, by the Order, authorises the DOE to function as the NESO.
	EPCA, Section 254.	Authorises the NESO to transmit to the IEA information and data related to the energy industry necessary to carry out the IEP.
	The Energy Supply and Environmental Co-ordination Act, Section 11. The Federal Energy Administration Act, Section 13.	Authorises the NESO to collect confidential or proprietary oil supply information or data from U.S. oil companies.
	B. Oil stockholding	
	EPCA, Section 151-167.	These Sections of the EPCA provide for the establishment of the Strategic Petroleum Reserve (SPR) to be available for the purposes of reducing the impact of future disruptions in supplies of petroleum and fulfilling obligations under the I.E.P.
	C. Implementation of oil stockdraw and other oil emergency response measures	
	EPCA, Section 3(8).	This section defines severe energy supply interruption, a key criterion the President is to use in deciding whether a drawdown of the SPR is called for.
	D. Natural gas emergency response organisations and measures	
	Natural Gas Policy Act 1978.	Authorises the US President to declare, and respond to, a natural gas supply emergency. (Powers have been delegated to the Deputy Secretary of Energy).
	International Emergency Economic Powers Act.	In the event of an unusual or extraordinary threat, the US President is authorised to declare a national emergency and to investigate, regulate or prohibit the import or export of any property (including natural gas) in which any foreign country or foreign national has an interest by any person or with respect to any property subject to US jurisdiction.
	EPCA.	Provides the US President with additional independent rule-making authority to restrict natural gas exports.
	Natural Gas Act.	Section 3 authorises DOE (subject to a hearing at which good cause must be demonstrated) to issue supplemental orders that modify or rescind prior orders to import or export natural gas to protect the public interest.
		Section 16 also authorises DOE to "perform any and all acts and to prescribe, issue, make, amend and rescind such orders, rules and regulations as it may find appropriate" to carry out its responsibilities.

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Developments in IEA emergency mechanisms 1974–2014

This Annex outlines the main developments contributing to the emergency preparedness of the IEA since the plan for its creation was put forward at the Washington Energy Conference of February 1974.

1974

February-October: The Washington Energy Conference chaired by Mr. Henry Kissinger and subsequent work by the Energy Co-ordination Group in Brussels resulted in the negotiation of the Agreement on an International Energy Program (The I.E.P. Agreement) as a legally binding international agreement.

November: Sixteen of the 24 Organisation for Economic Co-operation and Development (OECD) member countries signed the I.E.P. Agreement and form the International Energy Agency (IEA), an inter-governmental autonomous agency of the OECD. The 16 signatories of the IEP are: Austria, Belgium, Canada, Denmark, Germany, Ireland, Italy, Japan, Luxembourg, the Netherlands, Spain, Sweden, Switzerland, Turkey, the United Kingdom and the United States.

The IEP outlines three main objectives: to reduce IEA member countries' dependence on imported oil; to secure a commitment from member countries to hold minimum levels of emergency reserves (equal to 60 days of net imports); and to establish an agreement to share available oil supplies in the event of a major supply disruption.

1975

February: Norway agreed to participate in the work of the IEA under the terms of a special agreement.

The Industry Advisory Board (IAB) was established. In the event of the activation of the emergency system, the IAB is responsible, through its Industry Supply Advisory Group (ISAG) for the practical execution of the allocation programme under the supervision of the IEA.

May: The First IEA Ministerial Meeting reviewed the world energy situation, confirmed that an emergency response system was in place which could be activated whenever needed and set guidelines for the Agency's future work.

September: IEA countries agreed to increase their emergency oil reserve commitment from 60 to 70 days of net oil imports by the beginning of 1976.

1976

October: The first Allocation Systems Test (AST-1) was carried out, with the goal of assessing the effectiveness of technical machinery, communications and procedures necessary in an emergency to implement the IEP oil sharing programme.

November: IEA member countries agreed to increase their emergency oil reserve commitment to 90 days of net imports by the beginning of 1980.

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1977

January: New Zealand joined the IEA.

July: Greece joined the IEA.

October: The Second IEA Ministerial Meeting agreed on *12 Principles for Energy Policy*; it also initiated the annual review of the energy policies and programmes of member countries.

1978

April: The AST-2 was carried out and, for the first time, involved reporting company affiliates and the NESOs of member countries.

December: In response to the cessation of exports from Iran following the revolution, the IEA activated the emergency data system. During its period of activation, disrupted supplies remained above the threshold for triggering the IEP Emergency Sharing System. The world oil market is estimated to have lost 5.6 mb/d of gross peak supply during this period.

1979

March: Given the tightness of oil supplies, the IEA Governing Board[1] agreed to guidelines for member countries to reduce oil consumption.

May: Australia joined the IEA.

October: The AST-3 was carried out. The scope of the disruption assumed during this test was considerably larger than in the first two tests. Communications between the ISAG and NESOs improved as the prohibition of direct contact between these two groups was eliminated. Further, the addition of a deputy manager and a marine adviser strengthened the ISAG.

1980

July: The IEA Governing Board established the IEA Dispute Settlement Centre, which provided a voluntary system of binding arbitration for disputes among participating oil companies arising out of oil supply emergency actions.

October: The Governing Board agreed on measures to reduce oil consumption by some 5%, across the IEA member states. This was in response to the Iran-Iraq war that broke out in late September. The gross peak supply loss is estimated at 4.1 mb/d.

1981

July: Portugal joined the IEA.

December: A Decision on Preparation for Future Supply Disruptions was reached. Since disruptions in oil supply which do not reach the level required to trigger the emergency allocation system could cause damage to the economies of IEA member countries through sharp oil price increases, a new monthly information system on short-term supply prospects was introduced.

1. The IEA Governing Board is the IEA highest political decision-making body comprising ministers and/or their representatives.

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1983

May: The AST-4 was carried out. An improved data processing system designed to handle voluntary actions by participating oil companies to reallocate oil was tested. For the first time, voluntary offers of oil from NESOs on behalf of non-reporting companies played an important role in balancing allocation rights and obligations.

1984

July: The Governing Board agreed to establish procedures to enable governments to implement promptly early co-ordinated stockdraw and other measures in the event of a significant supply disruption. The procedures were termed Co-ordinated Emergency Response Measures (CERM).

1985

October-November. The AST-5 was carried out. A number of NESOs simulated the drawdown of oil stocks (government and company) for the first time. New procedures for resolving trade discrepancies between companies and countries were tested. Also, all initial data transmission and processing procedures were accelerated.

1988

January: The first CERM test was conducted during January and February.

July: The CERM Operations Manual was adopted by the Governing Board.

October: AST-6 was held in October and November. In this test, for the first time, countries and companies were given the option to have a direct computer-to-computer link with the IEA for submitting emergency questionnaires. Also, a computer software version of the questionnaires was developed to speed up producing, receiving and processing of questionnaire information.

1990–1991

August 1990-February 1991: The Iraqi invasion of Kuwait on 2 August removed some 4.3 mb/d of oil from the market. The Governing Board agreed on 9 August that individual countries should, where possible, strengthen their individual eff orts to increase available oil supplies. However, given the risk of a further supply loss from the Gulf in the event of hostilities, the Governing Board, with the participation of France, Finland (these two countries were not yet members of the IEA) and Iceland, unanimously decided in January 1991 on a Contingency Plan to make available to the market 2.5 mb/d of oil. Stockdraw accounted for some four-fifths of the 2.5 mb/d response. The remaining one-fifth (0.5 mb/d) consisted of demand restraint (0.4 mb/d), fuel switching (0.1 mb/d) and increased indigenous production.

On 28 January 1991, the Governing Board decided the Contingency Plan would remain in effect and would be implemented flexibly, according to supply/demand developments. Seventeen OECD member countries made stocks available according to their national situation. Some countries offered oil to the market from strategic stocks, whereas others reduced industry stockholding obligations, and yet other countries made arrangements with private companies for oil to be made available to the market.

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1992

January: Finland joined the IEA.

August: France joined the IEA.

October-November: The AST-7 took place; in this test Finland, France and Germany's eastern *Länder* participated for the first time.

Based on the experience of the Gulf Crisis and the AST-7, a review of IEA emergency response measures was initiated and a revision of the *Emergency Management Manual* was started.

1994

February: IEA procedures for stockholding and stockdraw were reviewed at a workshop involving IEA member countries, the Czech Republic, Hungary, the Republic of Korea, Thailand and oil industry experts of the IEA IAB.

The IEA Governing Board adopted a revised *Emergency Management Manual* covering all operations required by the IEA Secretariat, governments and oil companies in a severe emergency.

1995

February: A Governing Board Decision confirmed the need to enhance emergency response flexibility and emphasised that priority should be given to the use of co-ordinated stockdraw and other measures, regardless of the size of the disruption and before activation of the allocation mechanisms.

October-November: A comprehensive test of the emergency data system was held involving all IEA governmental emergency departments and international oil companies operating within IEA member countries.

1996

June: The IEA Conference on Long-Term Oil Security reviewed IEA strategy against the background of oil security as a global concern.

1997

April: The IEA Global Oil Security Conference involved participation by ten non-IEA countries and several non-IEA country regional energy organisations. Non-IEA country participants were briefed on a range of IEA emergency response measures.

June: Hungary joined the IEA.

1998

May: The seminar: The Effects of the Oil Price Drop of 1997/98 examined the short-term and potential long-term effects of a sustained price drop on oil-producing countries as well as oil consumers.

November: The emergency response exercise (ERE) was held. Its main objectives were to representatives of governments of IEA countries and oil company personnel in IEA emergency procedures. The exercise included the preparation of a three-stage IEA emergency response over a three-week period. This was followed up by training and discussions in Paris and included a surprise scenario exercise.

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1999

September: An Oil Stockholding Seminar and a two-stage Disruption Simulation Exercise were held as part of the follow-up work of the ERE.

The main objective of the seminar was to assess the current IEA stock situation and develop a strategy for the maintenance and use of emergency stocks in a future oil crisis. The purpose of the Disruption Simulation Exercise was to use hypothetical scenarios in a real-time setting to enhance understanding of the probable development of market reactions in an emergency, with a view to improving the speed and effectiveness of IEA emergency response.

2000

April: An ad hoc informational meeting of the Standing Group on Emergency Questions (SEQ) was held on the oil supply situation of Serbia/Montenegro/Kosovo in response to the oil embargo initiated by NATO, the European Union and Bulgaria, in an effort to deny oil to Yugoslavia. The use of an embargo on oil deliveries by (some) IEA countries and applicant countries in a collective manner was unprecedented.

May: With the IEA/ASCOPE Seminar on Asian Oil and Energy Security held in Kuala Lumpur, Malaysia, the IEA strengthened ties with non-IEA countries, especially those with increasing consumption of oil.

2001

February: The Czech Republic joined the IEA**.**

April: The IEA welcomed the decision by the Chinese government to build emergency oil stocks which was announced during a joint IEA-China Workshop on Emergency Oil Stock Issues in Paris.

2002

March: Korea joined the IEA. The ERE 2 took place in Paris.

October: The Governing Board approved the Initial Contingency Response Plan. This flexible plan is developed in order to facilitate rapid decision-making by the Governing Board during an oil supply crisis.

2004

January: Responding to India's interest in emergency stockholding, the IEA and India shared information at a workshop on Emergency Oil Stock Issues in New Delhi, India.

April: The IEA shared its expertise with Asian countries during a joint IEA/ASEAN/ASCOPE workshop held in Cambodia on Oil Supply Disruption Management Issues.

October: The ERE 3 took place in Paris, with simulation exercises involving Governing Board members and representatives from ten non-IEA countries.

2005

September-December: On 2 September, in the immediate aftermath of Hurricane Katrina in the Gulf of Mexico, the IEA announced the agreement of member countries to make available to the market the equivalent of 60 million barrels of oil. It was estimated that the gross peak supply loss reached 1.5 mb/d. The announcement came only 48 hours after the hurricane struck, thus demonstrating the ability of the IEA to react swiftly to a crisis. The collective action was officially terminated on 31 December, 2005.

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2006

June: Responding to the increased dependence on natural gas in IEA countries, the IEA held a Workshop on Security of Gas Supply.

2007

September: The IEA/ASEAN Workshop on Emergency Oil Stockholding was held in Bangkok, Thailand.

November: The Slovak Republic joined the IEA.

December: Officials from China and India attend IEA committee meetings.

2008

September: Poland joined the IEA.

2009

October: At the Ministerial Meeting, IEA Ministers agreed that "The IEA can play a strong role in helping member countries improve their preparedness for possible gas supply disruptions, and coordinate their actions in case of an emergency, when appropriate". More specifically, with respect to emergency response capabilities for natural gas, Ministers agreed to endorse a role for the IEA to monitor progress in gas markets and gas security policies of its member countries.

2011

June: On 23 June, the IEA announced a collective action in response to the ongoing supply disruption of Libyan light sweet crude, an anticipated oil demand increase in the third quarter, and to act as a bridge to incremental supplies from major producers. All 28 IEA member countries agreed to make available to the market the equivalent of 60 million barrels from the emergency stockpiles of eight larger IEA countries. Some 38 million barrels were drawn from public stocks and 22 million barrels were made available through the lowering of stockholding obligations on industry. Roughly 40 million barrels of the emergency stocks were in the form of crude oil, and the remainder in refined products. The collective action was officially terminated on 15 September 2011 and countries were encouraged to exercise flexibility in re-establishing emergency stock levels through 2011 and 2012.

2014

May: Estonia joined the IEA.

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List of acronyms

ADIF	*Administrador de Infraestructuras Ferroviarias* (Spain) State-owned Spanish Railway
AGN	Association of Natural Gas Distributors (Chile)
AGS	Ahuroa Gas Storage (New Zealand)
ANRE	Agency for Natural Resources and Energy (Japan)
APETRA	Petroleum Agency (Belgium) *Agence de Pétrole – Petroleum Agentschap*
API	American Petroleum Institute (gravity measure)
APM	Administrative Pricing Mechanism
APSA	ASEAN Petroleum Security Agreement
ARA	Amsterdam, Rotterdam and Antwerp (area)
ASEAN	Association of Southeast Asian Nations
ASMR	Administration of State Material Reserves (Czech Republic)
ASMR	Administration of State Material Reserves (Slovak Republic)
AST	Allocation Systems Test
AWP	Adria-Wien Pipeline
BAFA	Federal Office of Economics and Export Control (Germany)
BBL	Balgzand to Bacton Pipeline
BEMIP	Baltic Energy Market Interconnection Plan
BMWi	*Bundesministeriums für Wirtschaft und Energie* (Germany) Ministry for Economic Affairs and Energy
BOTAŞ	Petroleum Pipeline Corporation (Turkey)
BPLC	Bharat Petroleum Corporation Limited (India)
CAG	Common Arrangements for Gas (Ireland)
CAPA	Crude Against Products Agreement (Belgium)
CBM	coalbed methane
CCGT	combined cycle gas turbine
CCHEN	Chilean Nuclear Energy Commission
CCO	critical contingency operator
CDGSC	Government Delegate Commission Committee for Crisis Situations (Spain)
CEI	*Commission Économique Interministérielle* (Belgium) Inter-Ministerial Economic Commission
CEL	Central European Line (crude oil pipeline)
CEPC	Civil Emergency Planning Committee, NATO
CEPA	Canadian Energy Pipeline Association
CEPS	Central European Pipeline System
CER	Commission for Energy Regulation (Ireland)
CERM	co-ordinated emergency response mechanism
CESS-NGS	Commission for Enduring and Supervising Security of Natural Gas Supply (Turkey)
CHP	combined heat and power
CLC	*Companhia Logística de Combustíveis* (pipeline, Portugal)

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CLH	*Compañía Logística de Hidrocarburos* (oil pipeline, Spain)
CNC	National Competition Commission (Spain) *Comisión Nacional de la Competencia*
CNG	compressed natural gas
CNGC	China North Industries Group Corporation
CNOOC	China National Offshore Oil Corporation
CORES	*Corporación de Reservas Estratégicas de Productos Petrolíferos* (Spain) Corporation of Strategic Reserves of Petroleum Products
COSMOS	Cyprus Organisation for Storage and Management of Oil Stocks
COVA	*Centraal Orgaan Voorraadvorming Aardolieproducten* (stockholding agency, Netherlands)
CPSSP-SAGESS	*ComitéProfessionnel des Stocks Stratégiques Pétrolier – Société Anonyme de Gestion des Stocks de Sécurité* (France)
CREG	*Commission de Régulation de l'Electricité et du Gaz* (Belgium)
CSE	Central Stockholding Entity
CSG	coal seam gas
CSO	compulsory stockholding obligation
CSREM	National Energy and Mining Resources Committee (Spain)
CWaPE	*Commission wallonne pour l'Energie* (Belgium)
CWS	Country Wide Stock (Brunei Darussalam)
DCENR	Department of Communications, Energy and Natural Resources (Ireland)
DEA	Danish Energy Agency
DECC	Department of Energy & Climate Change (UK)
DEPA	Greek Public Gas Corporation
DESFA	National Natural Gas System Operator SA (Greece)
DGEC/DG	General Directorate for Energy and Climate Change/Directorate for Energy (France)
DGEG	Directorate General for Energy and Geology (Portugal)
DMA	Disaster Management Act (India)
DOE	Department of Energy (US)
DOPCO	Daehan Oil Pipeline Corporation (Republic of Korea)
DRA	drag reducing agent
DSO	distribution system operator
EBV	*Erdölbevorratungsverband* (oil stockholding agency, Germany)
EERC	Energy Emergency Response Centre (Korea)
EGREP	*Entidade Gestora de Reservas Estratégicas de Produtos Petroliferos* (stockholding company, Portugal)
EIA	Energy Information Administration (US)
ELG	*Erdöl Lagergesellschaft* (Austria)
EMRA	Energy Market Regulatory Authority (Turkey)
ENAP	Chilean National Oil Company (Chile)
ENI	*Ente Nazionale Idrocarburi* (oil company, Italy)
EOF	Danish Oil Industry Association
EOSA	Emergency Oil Stocks Agency (Slovak Republic)
EPA	Environmental Protection Agency (US)
EPCA	Energy Policy and Conservation Act (US)

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ERA	Emergency Response Assessment (non-IEA countries)
ERE	Emergency Response Exercise
ERGEG	European Regulators' Group for Electricity and Gas
ERR	Emergency Response Review (IEA member countries)
ESAB	Energy Supplies Allocation Board (Canada)
ESE	Energy Supplies Emergency Act (Canada)
ESPO	Eastern Siberia-Pacific Ocean (oil pipeline)
ETBE	Ethyl tert-butyl ether
EU	European Union
EÜAŞ	Electricity Generation Company (Turkey)
FDO	*Foreningen Danske Olieberedskabslagre* (stockholding agency in Denmark)
FGSZ	FGSZ Natural Gas Transmission Closed Company Limited (Hungary)
FLNG	floating LNG (terminal)
FONES	Federal Office for National Economic Supply (Switzerland)
FSRU	floating storage and regasification unit
FSU	Former Soviet Union
FY	financial year/fiscal year
FYROM	Former Yugoslav Republic of Macedonia
Geq	Groningen equivalent (gas)
GERT	Gas Emergencies Response Team (Ireland)
GPSS	Government Pipeline and Storage System (UK)
GTL	gas-to-liquids technology
GTS	Gasunie transport services (Netherlands)
HEO	Hungarian Energy Office
HFO	heavy fuel oil
H-gas	high-calorific gas
HPCL	Hindustan Petroleum Corporation Limited (India)
HUSA	Hungarian Hydrocarbon Stockpiling Association
IEP	International Energy Program (Agreement)
IAB	Industry Advisory Board, IEA
ICRP	Initial Contingency Response Plan (Ireland)
IEA	International Energy Agency
IEEPA	International Emergency Economic Powers Act (US)
IGB	Interconnector Greece-Bulgaria
IJS	International Joint Stockpile (Project)
IKL	Ingolstadt-Kralupy-Litvínov pipeline
IOC	international oil company
IOCL	Indian Oil Corporation Limited (India)
ISAG	Industry Supply Advisory Group, IEA
ISO	independent system operator
ISPRL	Indian Strategic Petroleum Reserves Limited (India)
ITGI	Interconnector Turkey-Greece-Italy
JOGMEC	pan Oil, Gas and Metals National Corporation

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JPDA	joint Petroleum Development Area (Australia, Timor Leste)
JV	joint venture
KEEI	Korea Energy Economics Institute
KEPCO	Korean Electric Power Corporation
KG D6	Krishna Godavari (basin) D6 (field)
KGV	*Koordinierungsgruppe Versorgung* (Germany) Supply and Co-ordination Group
KNOC	Korean National Oil Corporation
KOGAS	Korean Gas Corporation
KVR	*Krisenversorgungsrat* (Germany) Emergency Supply Council
LFA	Liquid Fuel Stocks Act (Estonia)
LFE	Liquid Fuel Emergency (Act) (Australia)
L-gas	low-calorific gas
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MÁSz	Hungarian Petroleum Product Association
MBIE	Ministry of Business, Innovation and Employment (New Zealand)
MC	metering and control (station)
MCDEM	Ministry of Civil Defence and Emergency Management (New Zealand)
MEAN	Ministry of Economic Affairs of the Netherlands
MENR	Ministry of Energy and Natural Resources (Turkey)
METI	Ministry of Economy, Trade and Industry (Japan)
MND	*Moravské naftové doly* (oil and gas producing company, Czech Republic)
MOL	Hungarian Oil and Gas Public Limited Company
MoPNG	Ministry of Petroleum and Natural Gas (India)
MOR	minimum operating requirements
MOSES	Model of Short-term Energy Supply Security, IEA
MOT	Maasvlakte Olie Terminal (Netherlands)
MOTIE	Ministry of Trade, Industry and Energy (Korea)
MoU	Memorandum of Understanding
MPE	Ministry of Petroleum and Energy (Norway)
MRA	Material Reserve Agency (Poland)
NAFTA	North American Free Trade Agreement
NAM	*Nederlandse Aardolie Maatschappij* (oil exploration company, Netherlands)
NATO	North Atlantic Treaty Organization
NCPC	China National Petroleum Corporation
NCS	Norwegian Continental Shelf
NDMA	National Disaster Management Authority (India)
NDRC	National Development and Reform Commission (People's Republic of China)
NEA	National Energy Administration (China)
NEB	National Energy Board (Canada)
NEC	National Energy Council (Indonesia)
NEC	Network Emergency Coordinator (UK)
NEHHOR	Northeast Home Heating Oil Reserve (US)

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NELP	New Exploration Licensing Policy (India)
NEOT	North European Oil Trade Oy (Finland)
NEP-F	National Emergency Plan for Fuel (UK)
NEP-G&E	National Emergency Plan for Gas and Electricity (UK)
NEPS	Northern European Pipeline System
NESA	National Emergency Supply Agency (stockholding agency in Finland)
NESO	national emergency strategy organisation
NGEM	national gas emergency manager (Ireland)
NGEP	natural gas emergency plan (Ireland)
NGERAC	National Gas Emergency Response Advisory Committee (Australia)
NGG	National Gas Grid (UK)
NGL	natural gas liquid
NGPA	Natural Gas Policy Act (US)
NLFERP	National Liquid Fuel Emergency Response Plan (Australia)
NNGS	National Natural Gas System (Greece)
NOB	National Oil Board (Belgium)
NOC	national oil company
NOEDRS	National Oil Emergency Demand Restraint Strategy (Australia)
NOGAT	Northern Offshore Gas Transport
NORA	National Oil Reserves Agency (Stockholding hovernmental body, Ireland)
NOSC	National Oil Stock Commission (Turkey)
NOSEC	National Oil Supplies Emergency Committee (Australia)
NOVE	Dutch association of independent fuel suppliers
NPR	National Petroleum Reserve
NTS	National Transmission System (UK)
OCSIT	Central Oil Stocks Entity (Italy)
OEB	Oil Emergency Board (Norway)
OECD	Organisation for Economic Co-operation and Development
OICP	Oil Industry Contingency Plan (India)
OIDB	Oil Industry Development Board (India)
OIL	Oil India Limited
OLPP	Oil stockholding company, Poland
OMV AG	*Österreichische Mineralölverwaltung* (oil company, Austria)
Onemi	National Emergency Office (Chile)
ONGC	Oil and Natural Gas Corporation Limited (India)
OPEC	Organization of the Petroleum Exporting Countries
OSPA	Estonian Oil Stockpiling Agency
OSRM	Oil Stockpiling Roadmap (ASEAN)
PAJ	Petroleum Association of Japan
PCI	Project of Common Interest (European Commission)
PDR	Petroleum Demand Restraint Act of 1981 (New Zealand)
PERN	Oil Pipeline Operation Company, Poland
PETDER	Turkish Petroleum Industry Association

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PFP	Point Forward Project (New Zealand)
PGNiG	Polish Petroleum and Gas Mining Company
PKN	*Polski Koncern Naftowy* (oil refiner, Poland)
PLIF	*Pipeline de l'Ile-de-France*
PLL	Petronet LNG Limited (India)
ppm	parts per million
PRH	Hydrocarbon Resources Plan (France)
PSU	Public Sector Undertakings (India)
RAE	Regulatory Authority for Energy (Greece)
RAG	Rohöl-Aufsuchungs-AG (Austria)
RAP	Refinery to Auckland Pipeline (New Zealand)
RAP	Rotterdam Antwerp Pipeline
REBCO	Russian Export Blend Crude Oil
RIL	Reliance Industries Limited (India)
RNTGN	Portuguese National Natural Gas Transmission Network
RRP	Rotterdam-Rhine Pipeline
SAPPRO	*Société du pipeline à produits petroliers sur le territoire genevois* (Switzerland)
SCER	Standing Committee on Energy and Resources (Australia)
SDMA	State Disaster Management Authority (India)
SEA	Swedish Energy Agency
SEC	Superintendency of Electricity and Fuels (Chile)
SECO	State Secretariat for Economic Affairs (Switzerland)
SEQ	Standing Group on Emergency Questions, IEA
SFOE	Swiss Federal Office of Energy
SGRI	South Gas Regional Initiative, ERGEG (Spain)
Sinochem	China National Chemicals Import and Export Corporation
Sinopec	China Petrochemical Corporation
SNIP	Scotland-Northern Ireland Pipeline
SOTEG	*Société de transport de gaz* (Luxembourg)
SPBI	Swedish Petroleum and Biofuels Institute
SPM	single point mooring
SPR	Strategic Petroleum Reserve (US)
SPSE	*Société du Pipeline Sud-Européen* (oil pipeline in France and Germany)
SPV	Special Purpose Vehicle
SSO	storage system operator
SvK	*Affärsverket svenska kraftnät* (Swedish Grid)
SWL	South West Lobe gas field (Ireland)
SYPG	Shaanxi Yanchang Petroleum Group (China)
TAL	Trans-Alpine Pipeline
TAL-IG	Trans-Alpine Pipeline Trieste to Ingolstadt
TANAP	Trans-Anatolian Natural Gas Pipeline
TAP	Trans-Adriatic Pipeline
TEİAŞ	Turkish Electricity Transmission Corporation

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TETAŞ	Turkish Electricity Trading and Contracting Company
TIGF	*Total Infrastructure Gaz* (France)
TMPL	Trans Mountain Pipeline (Canada)
TPAO	Turkish Petroleum Corporation
TPES	total primary energy supply
TSO	transmission system operator
UAE	United Arab Emirates
UGS	underground gas storage
VLCC	very large crude carrier
VNPI	Netherlands Petroleum Industry Association
VOTOB	Association of Independent Tank Storage Companies (Netherlands)
VREG	*Vlaamse Reguleringsinstantie* (Belgium) Flemish Regulation Entity for the Electricity and Gas market
WCSB	Western Canada Sedimentary Basin
WEO	*World Energy Outlook*
WEPP	West-East Pipeline Project (I, II and III)

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ENERGY SUPPLY SECURITY

Emergency Response of IEA Countries 2014

Ensuring energy security is a core responsibility of the International Energy Agency and a priority for its member countries. To this end, the ability to respond quickly and effectively in the event of a supply disruption is essential. *Energy Supply Security: The Emergency Response of IEA Countries* (2014) provides an overview of the most recent oil and natural gas emergency policy reviews of the 29 IEA member countries as well as those of key partners such as Chile, China, India and ASEAN. The publication assesses each country's emergency arrangements for security of supply of oil and gas, their stockholding structure, demand restraint measures and fuel switching capacity, and also provides a summary of energy security best practices among the IEA membership and beyond.

Although the IEA was initially created to focus on oil supply security, energy markets have evolved, with other fuels playing increasingly important roles in the global energy mix. Thus, natural gas is highlighted in this publication, including assessments of measures to respond to and offset potential supply disruptions. Due to the increasing dependence of modern societies on reliable and secure electricity supplies, this publication also includes an overview of the electricity security assessment framework recently developed by the IEA for the purposes of strengthening countries' electricity security.

In compiling conclusions from the latest cycle of emergency preparedness reviews, the objective of this publication is to provide a useful tool of reference to governments enabling them to strengthen their emergency policies across the energy mix and thus minimise the impact of a supply disruption.