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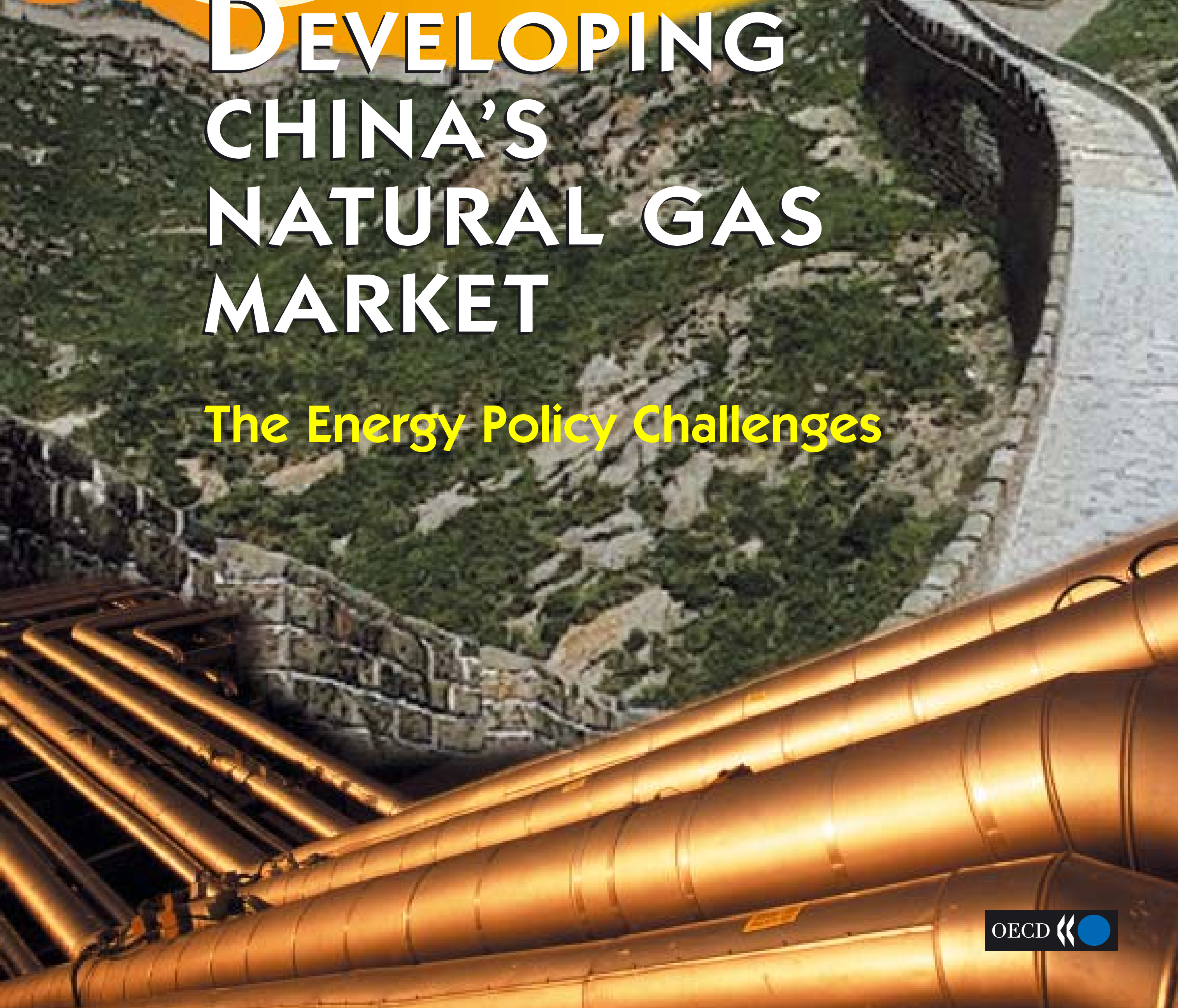

DEVELOPING CHINA'S NATURAL GAS MARKET

The Energy Policy Challenges

OECD

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- to maintain and improve systems for coping with oil supply disruptions;
- to promote rational energy policies in a global context through co-operative relations with non-member countries, industry and international organisations;
- to operate a permanent information system on the international oil market;
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- to assist in the integration of environmental and energy policies.

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FOREWORD

To develop its natural gas market to the size envisaged by its planners within a relatively short time, China has to tackle a number of important challenges. Other countries, within the IEA and outside, have faced similar challenges in developing their gas markets; but the challenges faced by China are greater. Chinese gas reserves are relatively limited and are located far from the main centres of demand; cheap alternative fuels are available - in particular coal; there is a lack of gas-related technologies and skills; and knowledge of how best to develop markets is not widespread. Chinese policy-makers recognise gas as the fuel of choice for environmental and energy diversification purposes and for its potential contribution to the modernisation of industrial activities. The Chinese government's strong determination to develop a gas market now needs to be translated into concrete policy action.

This report, the first of its kind in the Agency's relationship with China, attempts to address these challenges. It suggests which policies and measures, both within the natural gas sector and outside, can best foster the development of the gas industry and market.

A key conclusion of the study is that many of the challenges China faces in developing its gas market are not confined to the gas industry, but require policies affecting the national energy economy as a whole. China's natural gas market cannot and should not be developed in isolation from the rest of the energy system and economy.

This study was carried out by the IEA under the terms of the 1996 Memorandum of Policy Understanding in the Field of Energy with the Chinese government. Although the report draws on Chinese government sources and benefits from the contributions of many individuals, it is not a joint report and therefore does not necessarily reflect the views or positions of the Chinese government. However, we hope the Chinese authorities will regard the recommendations in the report as a useful contribution to the realisation of their commitment to develop China's gas market.

The report is published under my responsibility as the Executive Director of the IEA.

Robert Priddle,
IEA Executive Director

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This report has been prepared thanks to contributions from a number of people from Chinese government administrations, research centres, and energy companies, as well as from international energy companies operating in China, IEA member countries and the IEA Secretariat.

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- State Power Corporation of China (SPCC); and
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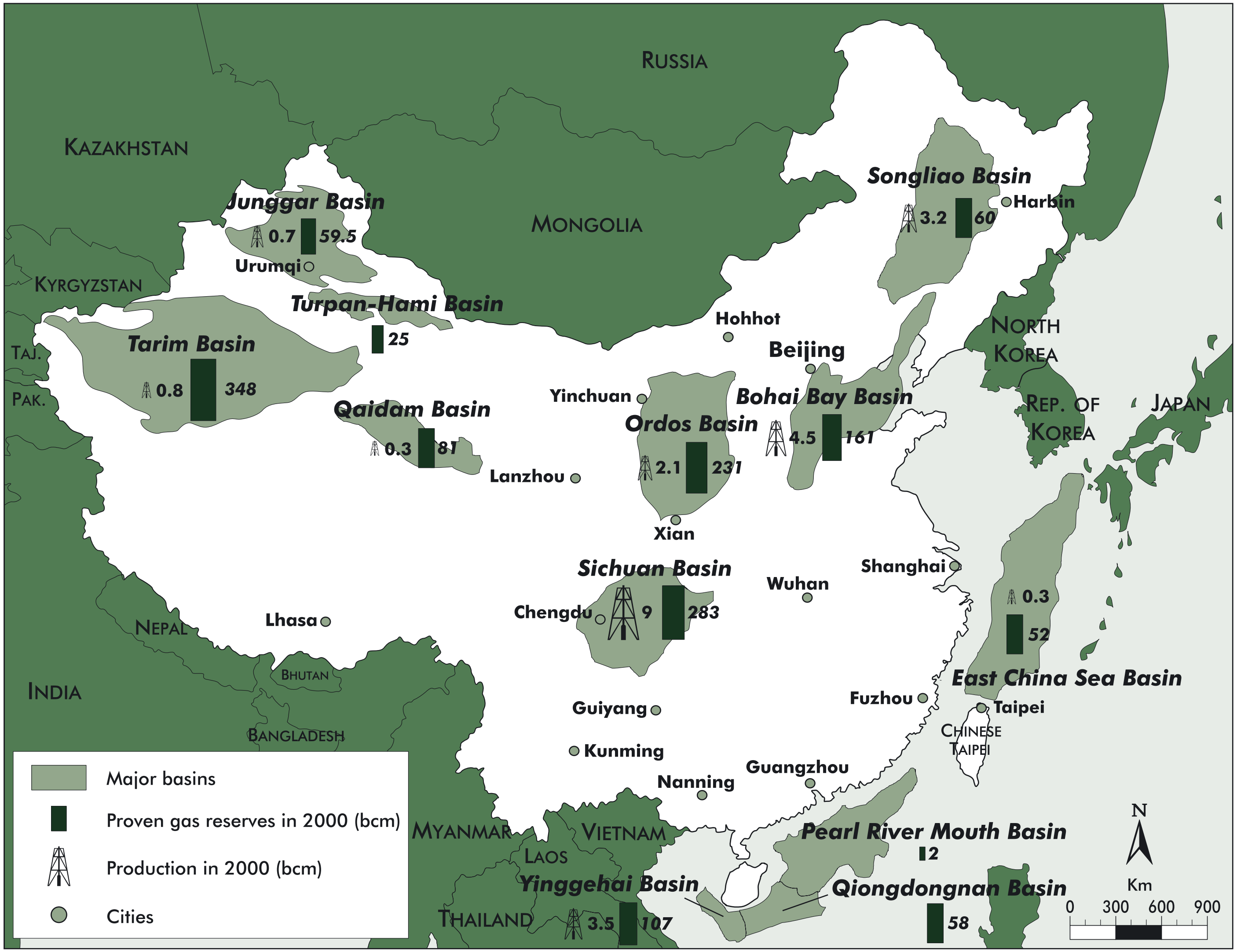
Xavier Chen was the principal author and co-ordinator of the study. All comments and questions should be addressed to him at: Dr. Xavier Chen, China Programme Manager, International Energy Agency, 9, rue de la Fédération, 75015 Paris, France. Tel: +33 1 4057 6512; Fax: +33 1 4057 6579; E-mail: xavier.chen@iea.org

Map 1

Map of China

Map 2

Natural Gas Reserve and Production in China's Main Gas Basins in 2000



Map 3

Existing Gas Supply Infrastructure in China

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EXECUTIVE SUMMARY

KEY MESSAGES

1. Only with strong policy drivers will it be possible to achieve the desired target of doubling the share of natural gas in China's energy supply mix within the next ten years. The challenge is in the downstream sector. In most parts of China, gas will find it hard to compete against coal in power generation. In local gas distribution, much needs to be done to convert from manufactured gas and expand the gas distribution network, to improve the financial health of local distribution companies, and to introduce commercial marketing and management.
2. Reform of natural gas pricing and taxation policy is the best start. In a country like China where domestic gas reserves are limited and expensive, a good gas pricing policy has to be based on the consumers' willingness to pay. Government should leave market participants to agree on gas prices, and focus on effectively using taxation policies to encourage both the penetration of gas in end-uses and investment into the gas chain.
3. As the main purpose of developing the gas market is to reduce local air pollution mainly caused by scattered, low-altitude emission sources (e.g. residential heating and industrial boilers), the premium market for gas is with the replacement of fuels producing these emissions. To realise this premium, administrative measures like emission standards and restriction of fuel choice may be needed at the beginning, but it is only with the application of economic instruments like taxation, which favour gas over more polluting fuels, that gas demand increase can be sustained over the long term.
4. There are a number of benefits to developing decentralised power generation in urban areas through the deployment of a large number of medium-size (≤50MW) gas-fired generation units. Such a system would anchor the demand for gas, help to build a distribution network, provide the possibility of valorising the waste heat, and reduce urban pollution. The long-term future lies in even smaller units for combined heat and power or combined cooling, heating and power. But this would require changes in the energy supply of the cities concerned.
5. The development of a modern gas industry requires a number of indispensable elements including technical norms, standards for health, safety and environment, training of technical and commercial gas professionals and gas technology research and development ability. China should make sure that none of these indispensable elements constitutes a bottleneck. In particular, it should acquire domestic manufacturing and construction capacity of advanced end-use gas appliances and equipment.
6. In building long-distance gas pipelines and LNG terminals, a strong focus should be on developing end-use markets in correspondence with construction schedules

and the contracted arrival of natural gas. The alignments of interests and the allocation of risks/rewards across the value chain in a stable and transparent way are critical to the long-term success of these projects.

7. To raise the necessary funds to finance gas infrastructure building, China needs to enlarge the sources of financing, especially domestic ones. At the same time, it should minimise financing costs by reducing risks from the policy and regulatory sphere. Foreign investment and management skills are indispensable for swiftly developing a sizeable and modern gas industry, especially so in the crucial sector of local gas distribution. A coherent investment framework for private and foreign investment will be required.
8. A legal framework for the gas industry is indispensable. At this stage, China's legal and regulatory framework should focus on enabling investment rather than restricting it, while paying appropriate attention to a possible introduction of a third-party access regime at a future time.
9. The Chinese government should also go beyond the "project by project" approach by developing a coherent gas policy, to reflect the importance it attaches to natural gas and to address all issues related to the development of a gas industry. This could be achieved e.g. in the form of a "White Paper".
10. The challenges of developing a gas market in China are not confined to the gas sector. They concern a much larger number of actors and require policies that affect the national energy economy as a whole. The Chinese government should therefore integrate its gas policy into a national energy policy. A specialist energy department within the central administration is desirable, given the need for a co-ordinated energy policy in China.

MAIN CONCLUSIONS AND POLICY RECOMMENDATIONS

INTRODUCTION

In its 10th Five-year Plan (2001-2005) for the energy sector, the government of China confirmed its strong determination to increase the share of natural gas in the country's energy supply mix within the next five years and beyond. Evidence of this determination includes the construction of the country's first LNG import terminal in Guangdong and the decision to build the 4000-km long "West-East Pipeline" (WEP) to bring natural gas from the Tarim basin in the country's far west to Shanghai in its far east. The target is to double the share of natural gas in China's total primary energy supply by 2010 from the current level of 3 per cent, and to build a well-interconnected national gas supply network by 2020 from today's fragmented basin-to-market pipelines.

Such a policy is laudable in a country where coal provides two-thirds of the total commercial energy supply and the local, regional and global environmental problems caused by the use of coal seriously impede future development prospects. An increased role for natural gas in the country's energy mix will also address the expectations of an increasingly affluent population that requires higher quality and cleaner fuels. It will contribute to the country's energy security, as China today is already dependent on external sources for one third of its oil supply and this level is irreversibly increasing. It can also reduce the railway's burden of moving millions of tonnes of coal from the coal-rich north to energy consuming centres in the east and southeast of the country. The replacement of natural gas for coal will also allow the modernisation of industrial activities. A well-developed Chinese gas market would also be essential for the envisaged future Northeast Asian Natural Gas Pipelines Network, which would significantly enhance the energy supply security of the entire region.

Meeting such an objective requires a number of policy initiatives to remove the obstacles that are impeding natural gas market development in the country. Achieving such an ambitious target within a relatively short timeframe is particularly daunting. The challenge is not just to complete the WEP or the Guangdong LNG terminal on schedule, it is much greater:

- China as a whole is not endowed with abundant gas reserves. Its proven reserves stand at around 1.5 trillion cubic metres (tcm), accounting for less than 1 per cent of the world's total. Its available gas reserves are located far away from demand centres, requiring the construction of long-distance pipelines. Gas prices are relatively high compared to international levels and China does not have any domestic manufacturing capacity for gas turbines or combined-cycle gas turbines (CCGT).
- On the other hand, coal reserves are abundant in China, though their uneven distribution across the country also requires extensive transportation. Coal is cheap, much cheaper than natural gas, and is in over-supply in the country today. In addition, China also has

considerable manufacturing capacity in coal-burning technologies such as coal-fired industrial boilers or power plants.

- China's energy sector, just like its whole economic system, is going through a period of reform and transition. Such a transition could provide opportunities or cause uncertainties for the development of the gas market, depending on how it is managed. The structural reform of the power sector, which is being undertaken in China, will determine the use of gas for power generation in a significant way.
- Competition is strong for public funds for the construction of major gas infrastructure projects. This is not only because there are so many other energy or other projects to be funded (e.g. the Three-Gorges Dam, the west-east electricity transmission project, the south-north water transportation project, and many environmental clean-up programmes), but also because the government's policy seeks to promote private financing of these projects.
- A WTO member since 2001, China is still a transition economy with a heavy reliance on command and control approaches. Many project decisions are made by government committees rather than companies and their bankers. WTO membership is expected to significantly improve foreign investment conditions, but this will take time. WTO membership will also expose Chinese industries to more international competition, which could bring more market discipline to their investment decisions.

Under these circumstances, key challenges for the Chinese government as well as for all of China's gas market participants include:

- Effective and timely development of a downstream gas market to support the economics of gas infrastructure projects (pipelines and LNG terminals).
- Improving local gas distribution by converting from manufactured gas, expanding the distribution network, stimulating the financial health of local distribution companies (LDCs) and introducing commercial marketing and management.
- Reforming gas pricing policies in such a way that gas prices encourage end-use market development, while providing appropriate incentives for upstream development and infrastructure construction.
- Introducing competition wherever appropriate at the right time, while providing a certain degree of investment protection at the early stages of market development.
- Defining a national energy/natural gas policy that would reconcile the possibly conflicting interests between gas and non-gas fuels, within and outside of the gas industry and among gas-market players in the up-, mid- and downstream sectors.

These and other challenges are further elaborated in this summary. They are discussed in detail in the individual chapters of this report.

ABOUT THIS STUDY

This study is one of a number of co-operative activities the IEA has undertaken with the government of the People's Republic of China under a *Memorandum of Policy Understanding in the Field of Energy*, which was signed in October 1996. It is a follow-up to the joint IEA-

China Conference on Natural Gas Development held in Beijing in November 1999. The State Development Planning Commission (SDPC) is the main Chinese counterpart for this study as well as for many other co-operative activities between the IEA and China. The SDPC expressed the expectation that this study would provide policy recommendations adaptable to Chinese realities and operational for policy-makers.

This report is the result of the collective efforts of IEA Secretariat staff, member country experts, Chinese officials and experts, and international oil and gas companies operating in China. Particularly valuable inputs were received from the State Development Planning Commission (SDPC), the SDPC's Energy Research Institute, PetroChina, CNOOC, SINOPEC, State Power Corporation, Shanghai Planning Commission, Tongji University, a large number of Chinese oil and gas experts (see acknowledgement list), a number of international oil and gas companies that are operating in China (BP, Exxon Mobil, Gaz de France, Shell, Unocal and others), and investment banks including the Hong-Kong Shanghai Banking Corporation (HSBC).

The study begins with a description of China's economic, energy and environmental context (Chapter 1) and its gas market (Chapter 2), then addresses the following nine inter-connected subjects for developing China's natural gas markets:

- Gas market development strategy and policy framework (Chapter 3);
- Gas for power generation (Chapter 4);
- Local gas distribution (Chapter 5);
- Gas pricing and taxation (Chapter 6);
- Long distance gas pipelines (Chapter 7);
- LNG imports (Chapter 8);
- Gas infrastructure financing (Chapter 9);
- Foreign investment in the gas sector (Chapter 10); and
- Gas industry structure and regulation (Chapter 11).

Three annexes, including a case study of end-use competitiveness of natural gas in Shanghai, are also provided.

Based on a thorough analysis of each of the subject areas, and drawing from international experiences and lessons, the study formulates a set of policy recommendations for consideration by the Chinese government.

KEY CONCLUSIONS OF THE STUDY

The study draws the following key conclusions:

China's gas industry, while nascent, is poised for rapid growth

China's natural gas industry is at an early and formative stage. The current gas market is fragmented, with most gas being consumed near where it is produced. Existing gas pipelines often just connect one producer to one single consumer, both of which are state-owned entities. Only one third of the gas produced is really used for commercial energy purposes, with the other two-thirds being used internally by the oil and gas fields or as feedstock for fertilizer production. The effective market for gas as a commercial fuel is therefore very limited, amounting to only 10 billion cubic metres per year. This is also true for the amount of gas used for commercial power generation, which represented less than 1 per cent of PetroChina's total gas sales in 2000.

However, driven by an increasing recognition of the benefits of natural gas and by the need to diversify its coal-dominated energy supply, China's gas industry is poised to grow very rapidly in the coming decades. The construction of some major projects such as the WEP and the Guangdong LNG terminal are symbolic of China's commitment to natural gas, but will also lay down some of the infrastructure needed for rapid growth.

Huge demand potential needs to become a paying market

China, particularly its eastern coastal provinces, undoubtedly offers huge market potential for natural gas, driven by the size of its population, economic growth, and the increasing need for cleaner energy. But this potential may remain only theoretical if Chinese policy-makers do not take into account the relatively poor competitiveness of natural gas *vis-à-vis* alternative fuels, the marketing efforts required of gas sellers/distributors, and the realistic estimation of major challenges that must be overcome to build up the demand for gas.

Residential use and power generation are expected to be the two major drivers for natural gas demand in the immediate future. Residential gas demand, while gradual in its development, is less price sensitive than other sectors in the short term, but it is not constant over time. Base-load power generation can take large gas volumes in a relatively short time, thus providing load support for the pipeline or LNG projects, but its economics depend critically on gas prices. In most parts of the country, gas-fired base-load generation currently cannot compete with coal. Gas uses for chemical production other than fertilizer, though not addressed in the study, are also illusive: Chinese chemical producers that use expensive gas (either imported or transported *via* long-distance pipelines) must compete with others that have built their chemical plants at the well-head in gas fields in large gas-producing countries. Consequently, gas market development must, in the first instance, rely to an extent on a multitude of small and medium-sized consumer entities who must be convinced one by one to opt, willingly and happily, for natural gas as the fuel of choice and to pay for the cost of conversion.

The main competitor is coal

Cheap and abundant domestic coal is natural gas' major competitor, especially in power generation. Given the availability of cheap domestic coal and the smaller difference between the capacity costs of a domestically produced coal plant and an imported CCGT, in China it is hard to find the kind of premium in gas-fired generation that is available in many OECD countries. Although the government has introduced administrative orders to forbid or limit the construction of any new coal-fired power plants in certain areas, in particular those defined as the two-control zones[1], coal, which provides 80 per cent of China's total electricity, will remain

1 The two-control zones refer to "SO_2 Control Zone" and the "Acid Rain Control Zone". See their definition in Annex 1 of the present report.

the principal source of power supply in China. Even if gas does not have to compete with coal in the coal-restricted urban areas, it will still have to compete with "coal-by-wire", that is coal-fired plants located outside the restricted zone with electricity transmitted by wire.

Gas also faces sharp competition from coal in the industrial sector, where a coal-fired boiler can produce the same amount of heat for one third of the cost of a gas-fired unit. The introduction of administrative orders, such as those in Beijing, Shanghai and other major cities, banning the use of coal within urban areas and replacing it with gas, is likely to push industrial activities out to unrestricted suburban areas. These administrative measures alone are unlikely to sustain a high level of gas consumption in the industrial sector, which will face increasing WTO-induced competition.

Internalising the environmental and social costs[2] of coal into its price would significantly improve the competitiveness of gas *vis-à-vis* coal. But even if this were the case, the increased use of gas in power generation and elsewhere would be unlikely to reduce the absolute volume of coal use. It is clear that the clean use of coal will remain very high on China's energy policy agenda.

Translating the benefits of gas into its development driver remains challenging

The main driving force for increased gas use in China is the growing recognition of natural gas' many advantages over alternative fuels. This is particularly true where gas could replace coal to reduce local environmental pollution - both urban air quality in most Chinese cities, and acid rain that affects 40 per cent of China's territory. But obvious as these benefits may be, considerable difficulties remain in translating the benefits of gas into concrete projects. Imposing prohibitively high emission fees on coal-fired plants to make gas-fired generation competitive is unlikely to be feasible. Fostering the use of natural gas to replace coal in residential heating and industrial boilers, which are the main sources of local pollution, requires the application of both administrative measures and economic instruments.

Even though China has put in place a range of environmental laws and regulations on air pollution, the lack of adequate means for implementation makes most of them ineffective. The environmental agenda is so complex and vast that it cannot be adequately addressed solely by the State Environmental Protection Agency and its counterparts at provincial and municipal level. Furthermore, the systematic fiscal and budgetary problems facing the country as a whole make it difficult for environmental institutions to do their job – the gap between their assigned responsibilities and the resources at their disposal is growing. The "one-size-fits-all" approach to policy is proving increasingly insufficient to solve current environmental problems.

On the positive side, it is encouraging to note that the government has repeatedly promised to increase the budget for environmental activities and that new approaches and instruments, such as SO_2 emission fees and emission trading, are being tested. The government has also announced its intention to implement the European air quality standards by 2005. But much more needs to be done to make environmental protection a real driver in gas market development (see below).

2 In addition to the deterioration of health and living conditions due to coal-related pollution, the coal mining sector kills 5,000-6,000 miners each year in mining accidents.

Gas market development needs a more systematic and rigorous approach

Consistent with the infancy of its gas market, China has not yet put in place a number of elements that are indispensable for its systematic and rigorous development and for building a modern gas industry. These include:

- Lack of definition of gas quality: while international practices price natural gas in terms of its heat value (e.g. €/kWh or $/MBTU), China prices natural gas by cubic metre. Gas quality, in terms of heat value, pressure and temperature, could vary significantly for the same volume. Lack of quality definition leaves room for dispute and other problems in the future.
- Insufficient attention to the economic conditions of production in the evaluation of gas reserves. Unlike their western colleagues who pay more attention to the notion of commercial exploitability of reserves, Chinese geologists and researchers tend to reason in terms of gas resources (e.g. 38 tcm for the country's total) or in terms of geological reserves. These notions do not attach sufficient importance to their economic value.
- No rigorous approach to gas demand evaluation: most demand projections do not take into account gas price and the ability of gas to replace existing fuels. This lack of a rigorous demand projection may lead to inappropriate infrastructure planning and investment.
- No systematic approach to gas supply security, including storage and modulation: given that gas demand fluctuates hourly, daily and seasonally, cities all attempt to solve modulation problems individually, rather than using a systematic approach by the whole pipeline and distribution system.
- No methodical approach to converting the existing manufactured gas network and appliances to natural gas: currently each city conducts its own conversion campaign in its own way and everyone learns by doing. There is a lack of co-ordination between pipeline construction and the gas distribution system's conversion schedules.
- Gas contracts: important pipeline projects are started without firm supply and off-take contracts. Producers justify downstream market size by letters of intent, which are not real commitments and do not have sufficient commercial value for project financiers.
- Technical norms and standards: many norms and standards used in the gas industry worldwide are not applied in China, and existing ones need improvement to be internationally compatible.
- In contrast with the upstream sector for which China has produced good geologists and petroleum engineers, there is a lack of professional training and education programmes for engineers and economists for downstream gas businesses.

Natural gas pricing policy needs major reform

Relatively high natural gas prices add a very significant constraint to expanding the natural gas market in China. At above US$2/MBTU (or $12/barrel in oil equivalent terms) including the processing cost, China's well-head prices of gas are quite high compared to international levels. Producers claim that factors contributing to high gas prices include poor upstream conditions. For consumers, this suggests significant room for cost reduction. Adding to this high level of well-head prices is the high cost of distribution, where local distribution companies are often hugely over-staffed and local authorities impose a number of additional charges. Under these circumstances, making end-use prices affordable means that either local governments must heavily subsidise their distribution companies or high-pressure transmission pipeline companies get squeezed to reduce their tariffs – neither of which contributes to healthy market development.

One important conclusion of this study is that China's gas pricing policies need deep reform. The current practice of government setting nation-wide uniform well-head prices does not recognise the differences between basins and fields in terms of their technical and economic characteristics and the related individual development and production costs. Artificially setting different well-head prices according to end-user consumers introduces cross-subsidies that distort the functioning of the gas market. The old-style production quota and allocation system, which is still operational in the gas market today, is very much outdated compared to the needs of the market.

Furthermore, the new gas pricing policy put in place in 1997 is based on a cost-plus approach. Such an approach encourages gas production, as prices would take into account all costs while providing a reasonable rate of return. This approach is not suitable for China where gas reserves are limited and costly. Even countries with cheap and abundant gas reserves, where this approach was considered suitable, have abandoned it due to its ineffectiveness in sending the right market signals. For China, a good gas pricing policy has to start with consumers' willingness to pay.

The key point is that government-set or guided prices do not and will never be able to reflect the changing supply and demand. Such a pricing policy is not compatible with the need for long-term commitments by producers or consumers which are needed to develop gas infrastructure. The government should leave the market to decide gas prices and concentrate instead on protecting captive consumers, i.e., those consumers who, once connected to gas, have little or no ability to switch away from it, against unfair use of market power and on using taxation to provide incentives for gas market development.

The infant market needs an enabling policy and a legal and regulatory framework

The study concludes that the government has an important role to play in China's natural gas market development, but this role needs to be clearly defined. Government should be policy-maker and rule-setter, but not project manager. It should concentrate on developing a policy and regulatory framework, not managing projects.

China lacks both a clear definition of a gas policy and a legal framework for the gas industry. The need to work these out is becoming increasingly pressing.

Except for its brief statement of intent in the energy and oil sector's five-year plans and some project-specific measures, the Chinese government as yet has no clear and formal policy statement on natural gas, on its role in the energy mix and on the accompanying policies and measures to encourage its development. Policy practices that currently prevail in China's gas industry are determined by regional authorities on a project-by-project basis. As more and more projects are approved on this basis, exceptions and special rules multiply. While this approach provides flexibility in dealing with the specific characteristics of each project, it also creates confusion, involves a multitude of bureaucratic administrations, and provides opportunities for government intervention in projects that could normally be undertaken following normal commercial practices. The project-by-project approach seems to be the preferred policy practice in China, but it may lead to a general policy failure and prove to be ultimately very costly both in time and money. This lack of a coherent government policy for natural gas has been widely held accountable for the slow uptake of this clean fuel option. It also creates uncertainties for international companies who wish to invest in China's natural gas projects.

An appropriate legal and regulatory framework is needed. China has published a set of laws and regulations to govern upstream oil and gas activities, but lacks the legal and regulatory framework for mid- and downstream activities. The lack of such a framework creates uncertainties for investors and complicates gas transportation and distribution. In this regard, it is encouraging that the World Bank has been working with China on the downstream gas sector regulatory framework.

An important conclusion of the study is that the legal and regulatory framework for China's gas industry, given its relative infancy, should be enabling, in order to allow gas markets to develop rapidly. The study maintains that market liquidity, i.e., a better-developed market with important infrastructure capacity, should exist before market deregulation can be envisaged. In the absence of such infrastructure, imposing competition in infrastructure may well be premature and compromise infrastructure building. Competition to lower the cost of building gas infrastructure is perhaps more important at this stage. It is equally important to set the stage for competition. In designing the regulatory framework, policy-makers in China need to pay very close attention to the long-term need to ensure robust competition such as open access to gas infrastructure facilities (pipelines and LNG terminals).

In addition to the above conclusions, the study also identified a number of facts that demonstrate the government's determination to develop its gas markets, but raise further complications. They are described below.

China is pursuing a supply-push strategy

The study characterises China's strategy for gas market development as a supply-push strategy. This qualification is supported by a number of facts. These include the encouragement of gas production through successive increases in state controlled well-head gas prices, the practice of a cost-plus pricing regime for new gas projects, and the decisions to build large and long-distance pipelines at a time when the downstream demand was not yet in place. Such a strategy has not been proven elsewhere. Given that natural gas can be substituted by other energy sources in virtually all its applications, if it is not attractive compared to alternative fuels, end-users will not adopt it as the fuel of choice. In all IEA countries where gas is a significant fuel, gas markets have been led by demand.

There may be some justification for China to seek a different balance in a supply-push *versus* a demand-pull strategy: without a strong push from the supply side, it is difficult for the demand side alone to pull gas market development, given the availability of cheap and abundant domestic coal. The fact that major domestic oil and gas companies play an important role in the government's energy policy decisions is another part of the reason. However, there are substantial risks in pursuing the supply-push strategy if the end result is uncompetitive gas.

- A central point of departure relates to downstream gas market development and the competitiveness of gas in various end-use sectors. Proactive marketing policies will be needed to promote the use of natural gas. Gas pricing policy will also be critical: international experience shows that a gas market can be successfully developed only if gas is priced competitively against other fuels.
- A second challenge is the synchronisation of investments along the gas chain. Particular care needs to be taken to co-ordinate investments in upstream production and processing, pipeline construction, and the development of downstream distribution and consumption facilities. Important lessons need to be learned from the Ordos-Beijing pipeline or the Sebei-Lanzhou pipeline, where the lack of downstream investment and overall co-ordination seriously undermined the economics of the pipeline and upstream projects.
- A supply-push strategy through the building of large pipeline or LNG projects needs to pay particular attention to the development of "anchor" projects that can consume a large and stable volume of gas in a relatively short time.
- More realistic timing should prevail. Over-optimistic estimations of the time needed to build the downstream market may repeat the mistakes made in the Ordos-Beijing or Sebei-Lanzhou pipelines.

The government attempts to create gas demand by administrative means

Stimulating the demand for gas is the most critical issue for the development of China's gas sector. However, the state of both power generation and urban gas distribution sectors constitute important hurdles to building real commercial/bankable demand (see below).

- It is important to note that the Chinese government has taken a number of important administrative measures to stimulate the demand for natural gas. These include:
- Banning the use of coal within a specified area of large cities and the restriction of coal use in certain areas where SO_2 and acid rain are a particular problem (the "Two-Control Areas");
- Promoting gas-fired co-generation of heat and power in urban areas; and
- Administrative forcing of provincial authorities to take a certain amount of gas from the West-East Pipeline project.

Such an administratively stimulated demand (or mandated demand) may be needed to give an initial push, but it is unlikely to produce a critical mass in gas demand. Cities such as Shanghai have tried out the option of heavily subsidising the conversion of the existing manufactured gas network in the Pudong area, but this option may not be valid for most other cities. The administratively-created demand would need to be sustained over the long-term, and a more sustainable way of doing so is through market-reinforcing economic and financial measures. These measures should be incorporated into gas pricing and taxation policies in a way that would ensure the evolution to a sound economic basis for each link of the gas supply chain.

Long-term commitments are being promoted

Recognising the need for long-term commitments in gas off-take to justify large infrastructure investment, both the government and industry in China are actively promoting "take-or-pay" (TOP) contracts. Those contracts may be difficult to conclude for the following reasons:

- Large gas-fired power plants, which can be stable large gas consumers, will only sign TOP contracts with gas marketers if they are able to secure a corresponding power purchase contract with the power grid companies or directly with secure clients. Gas-fired power generation faces a number of problems, most critically the competitiveness of gas *vis-à-vis* coal. Uncertainty over the country's future power sector reform also poses problems.
- Petrochemical plants using gas as feedstock face severe competition both domestically and internationally. None of them will have a firm and guaranteed product outlet market, which will make them reluctant to commit themselves under a TOP contract for feedstock supply. They are also particularly sensitive to the proposed gas prices.
- At present, local distribution companies are generally loss-making. They need a huge amount of investment to develop their market and to carry out the conversion from manufactured gas to natural gas, which will require considerable time and effort. As their customers are all relatively small users whose demand volume is still relatively modest, they will also face difficulties in committing themselves to a long-term TOP contract.

Heavy intervention from central government was needed for cities such as Wuhan to conclude a TOP contract on gas off-take. In the future, designing the nature and durability of the intervention is a challenge for Chinese policy-makers.

Long-term commitments such as TOP contracts are undoubtedly needed to mitigate the gas off-take risks of infrastructure projects. But there are important preconditions. One such precondition is the competitive pricing of natural gas based on market values and sustainable net-backs to producers. Another is to prepare realistic estimates of gas demand for the future: where, for what purpose, what level, and when. Government-imposed price and off-take volume may provide an initial stimulus, but will not allow producers and consumers to establish a stable commercial relationship over the long-term. In the United States, the combination of long-term TOP contracts, a cost-plus pricing policy and an over-estimation of gas demand led to a major crisis for the entire gas industry in the 1980s. This is a very important lesson to be learned.

Long-term commitments must be founded on mutual dependence and trust between players along the gas supply chain. Producers, transporters and consumers are residents across the same river. Their interests in developing the gas market need to be aligned in a stable and well-balanced way over the long-term. Such long-term commercial interests are stronger and much more stable than political factors. They maintained the smooth flow of natural gas from Russia to Europe even during the coldest days of the Cold War era. In Europe, where long-term TOP contracts were widely used during the last 50 years, only a handful of them were ever brought to court for third-party arbitration.

KEY RECOMMENDATIONS

Each chapter provides a number of recommendations that are specific to the subjects it covers. In drafting these recommendations, the authors of the study bore in mind the Chinese government's expectations as to the "operationality" criterion. Key recommendations are as follows:

General recommendations

Take active measures to facilitate end-use gas market development

The most critical issue in China's gas sector is to develop the end-use market. The issue is even more crucial if Chinese policy-makers retain a supply-push strategy for gas market development. There is a growing recognition among China's gas sector players that the downstream market constitutes the weakest link in the gas chain.

On the whole, the most critical issue is to get right the economics of the whole gas supply chain. This requires a major reform of the gas pricing system and a redefinition of risk/return on investments along the gas chain. It also requires that the economics of alternative fuels be closely taken into account. But key to this would be the identification of sectors where natural gas would have the highest market value compared to existing fuels and to make sure that the economy of these sectors does not suffer from using natural gas. Only if such a study is carried out can a set of policy actions be tailored to each sector. The government can take a number of policy actions to facilitate the development of the downstream market, for example:

- Reform the gas pricing policy, by adopting a net-back approach based on the market replacement value of gas compared with alternative fuels;
- Promote switching to gas through financial incentives such as tax credits, low-interest loans and favorable depreciation rates, and by sector-specific measures based on detailed studies;
- Reduce/exempt taxes and local add-on charges on natural gas;
- Introduce an excise tax on competing fuels, fuel oil in particular;
- Facilitate and enable large gas off-takers such as power plants to fulfil their long-term commitments by ensuring respect for their power purchase agreements;
- Lighten the approval procedure for large gas end-use projects and improve procedural transparency;
- Encourage private and foreign investment in the local gas distribution sector;
- Increase investment in end-use gas technology development and in building domestic capability for absorbing gas-use technologies.
- Define and implement a systematic and rigorous approach to gas market development, by integrating all the necessary elements such as training of downstream gas professionals, definition of natural gas quality, integration of natural gas into urban planning, putting in place as soon as possible a set of technical and safety norms and standards, etc.
- Form several regional centres of excellence for gas market development and set up all the important components along the gas chain, ensuring that none of them becomes a bottleneck.

Individual policy actions to facilitate gas market building in power generation and local gas distribution sectors are presented in sector-specific recommendations (see below).

Make environmental protection a real driver for clean energy development

The growing awareness of the urgency in solving serious air pollution problems provides a golden opportunity for the growth of gas and other clean energy sources. However, such development depends critically on the credibility of the country's environmental commitments – expressed in real national determination translated into concrete programmes and actions. Significant work needs to be carried out to make institutions efficient in dealing with environmental issues, in defining the instruments to achieve environmental objectives, and in making the investments needed to bring money to environmental programmes. Local environmental protection authorities need to be appropriately empowered and resourced to carry out their work.

One important factor that must affect gas-coal competition is the reflection of environmental benefits and costs in economic considerations. Such a reflection can be achieved by "internalising" the environmental benefits of natural gas and applying the "polluter-pays-principle" to coal. As it is difficult to impose emission fees on coal use in residential and commercial sectors, as well as in small industrial boilers, the country may need to rely initially on command and control measures to induce the replacement of coal by other fuels. It can also acknowledge the environmental benefits of natural gas by reducing taxes on gas and gas-using appliances and increasing taxes on more polluting fuels.

In power generation and large industrial boilers, the selective use of economic instruments will be necessary in addition to strengthening the enforcement of existing environmental regulations. To start with, the price/penalty per ton of emission (SO_2, NOx, particulate) should begin to reflect the market value of emission permits taking into consideration health damage to the public. For that, the current system of SO_2 emission fees needs major reform[3].

Given the fact that natural gas is more expensive than coal, the Chinese government will have to decide how to support the environmental and energy diversification benefits of gas. Exploration and production costs can no doubt be reduced, but ultimately the incremental costs of introducing gas into the Chinese economy will be borne by Chinese consumers against the benefits of health and energy security improvement as well as the modernisation of industrial activities. Taxation is a powerful tool to achieve the right balance. Tax authorities need to take into account the energy and environmental policy objectives of the country in designing a fiscal regime that will encourage not only substituting gas for more polluting fuels, but also investment in the gas industry.

3 Such a reform could undertake the following actions:
- Fees should be applied to both profitable and unprofitable companies; they should be set according to the severity of pollution and should be extended to other pollutants (TSP, NOx and untreated waste water);
- SO_2 emission charge should be increased from the current level; each power company and each unit of a power plant should have an upper limit of SO_2 emission per year;
- Fees should be indexed to inflation and should increase with time to remain a real incentive to reduce pollution.
- Fees should be independent of the fuel source: they should be imposed equally on power plants using low-sulphur coal or high-sulphur coal.
- Links must be severed between fees collected by local Environmental Protection Bureaux and the use of these fees. Fees should be transferred directly to the General tax fund and should not be used either to fund EPBs or as loans to polluting plants.
- Based on the experience gained from the trial phase, SO_2 emission trading should be formally established.

Publish a "white paper" on natural gas policy

To meet the ambitious target for gas market development in China, there is a real need for the government to go beyond the "project-by-project" approach by publishing a comprehensive national natural gas policy. Such a policy could address issues of gas exploration, development, distribution, pricing, and marketing, as well as imports. It could also provide a sound financial and fiscal basis for attracting private and foreign investment in natural gas projects, including project financing, bidding process, taxation, land-use, pricing, etc. It could serve to establish a long-term gas strategy for the country.

In the "White Paper", the government should make a clear and formal statement of its policy objectives and long-term strategy for natural gas in China through 2020. Such a paper could also identify the instruments for achieving development goals, including the role of the public and private sectors, the elements for building a modern and competitive gas industry, the economic instruments the government will use to encourage market development, the legal and administrative processes, etc. The process of elaboration and consultation of such a paper is critically important: it should draw on as many actors as possible, both public and private, within and outside the central administration.

Establish a legal framework on natural gas

Preparation of a legal framework such as a national gas law is an urgent priority. Such a framework would provide a clear legal expression of the government's policy and strategy for gas industry development and the ground rules for the operation of the gas industry. International practice shows that almost every country where a natural gas industry has been established, whether based on indigenous resources or imports, has adopted a gas law or laws in the early stages of market development.

In China, given that the market size is relatively small and that most gas activities are under state control, it is understandable that there is as yet no law on the gas industry at national level. But as the interest in natural gas grows and more and more actors are getting involved in developing the market, there is a strong case for introducing a natural gas law as soon as possible. Adopting such a law would help create a more stable investment and operating environment, reduce uncertainty and investment risk, and consequently lower the cost of capital.

Such a law should cover the mid- and downstream natural gas business to deal with the specific characteristics of the industry. It should codify the roles, rights and responsibilities of different players as well as regulatory principles in the industry to reduce conflicts of interest and to ensure a level playing field for all. It should provide the legal basis for short-term gas market development activities, such as gas contract negotiations and enforcement. Lessons should be learned from the development of the country's electricity law to avoid gas legislation that risks not being flexible enough to cope with market evolution over the medium and long term.

Create a central administration for energy

Although this study focuses primarily on natural gas policy issues, it concludes that many of the issues, such as coal-gas competition, gas for power generation, gas pricing and investment, and the environmental driver for gas market development, need to be addressed within the context of a national energy policy. A central body is desirable to co-ordinate national energy policy issues.

Since the abolition of the Ministry of Energy in 1992, China does not have a single central-government entity in charge of energy policy and regulatory matters. Energy sector responsibilities are spread across several ministries, among them the SDPC, the State Economic and Trade Commission (SETC) and the Ministry of Land and Resources (MLR). The allocation of policy and regulatory responsibilities among these ministries is not well-defined. Both SDPC and SETC are comprehensive economic agencies, but they do not always have the necessary in-depth technical knowledge on complex issues related to the operation of the energy industry, in particular, the two network industries of electricity and natural gas. Furthermore, this lack of internal resources, coupled with the need for heavy involvement in project management of these ministries, leads them to call on energy companies to provide technical expertise. At a time when the government is strongly committed to removing policy-making and regulatory functions from state-owned companies, it needs to strengthen its own ability and resources for policy-making and regulation.

There is therefore a strong case for establishing a specialist energy department within China's central government, to manage policies on oil, gas, electricity, coal and other energy sources and markets. A number of other factors reinforce the call for the creation of such an energy department:

- As China's oil dependency grows there is a pressing need for a co-ordinated approach towards energy security;
- Competition in the electricity, oil and gas industries is just beginning, and there will be a need for specialised expertise within the government to resolve increasingly complex market-related issues in the future;
- China's WTO membership will further open China's energy sector and bring new international pressure on energy trade and investment;
- Concentration of energy knowledge and expertise in a single body would facilitate the formulation of macro-economic policies and accelerate problem resolution;
- There is a need for increased coherence and co-ordination in energy policy-making; and
- Better communication of energy policy decisions to industry stakeholders is also critical.

Without such a national energy policy co-ordinator, it may be difficult for multiple regulators to regulate simultaneously the individual policies of separate sectors such as oil, gas and electricity, taking into account environmental, regional development and urbanisation considerations. To be effective, such a co-ordinating department should be appropriately resourced in order to build strong information and analytical capabilities.

Sector-specific recommendations

Gas for power generation (Chapter 4)

Power generation is expected by many to be the largest gas consuming sector in the future. Rapid growth of electricity demand and the desire to diversify the power supply for environmental reasons are powerful incentives to gas-fired generation. The development of large-scale power generation is also critically important for anchoring large gas infrastructure projects, either pipelines or LNG. Realising this potential will not be easy. In many regions of China, gas is currently not competitive against coal in base-load, and what is needed in the power sector is new generating capacity for peak-shaving. A new phase of electricity market reform, which just started in China, also adds significant uncertainties to the future of gas-fired generation.

The premium market for gas-fired generation in China lies both in peak-load and in a distributed generation system that provides heating, cooling and power in populated areas *via* a large number of small/medium and decentralised units (50 MW or below). Those units offer basically the same economics as large ones; they can be installed close to demand centres and help reduce urban air pollution; their waste heat could be more easily used for other purposes; and their deployment can also help in building a local gas distribution system.

Key recommendations include:

- Where conditions permit, seek ways of promoting base-load gas-fired power generation to support the expedient development of a gas market and to anchor large-scale gas infrastructure development.
- Encourage the development of decentralised gas-fired generation by relatively small gas turbines, and where possible as heat and power co-generation, or heat, cooling and power tri-generation projects, and pursue this as a medium and long-term strategic orientation;
- Rationalise electricity pricing schemes to ensure that tariffs at wholesale levels better reflect costs of peaking and mid-merit generation;
- Take the historical opportunity of the electricity market reform to include pro-clean energy sources in the current power sector reform package; and make a clear policy pronouncement that sets the government's long-term vision for the power sector in order to reduce uncertainties;
- Tighten environmental regulations on coal-fired power plants and strengthen their enforcement.
- Exploit the potential of summer-winter complementarity in gas and electricity demand by promoting gas-fired air-conditioning systems and peak load generation.
- Develop the domestic capacity to build small and medium-sized gas turbines and CCGTs in China.

Local gas distribution (Chapter 5)

Local gas distribution is perhaps the most problematic sector. First, the majority of local distribution companies (LDCs) in China are financially unhealthy and rely on local government subsidies. Second, LDCs are accustomed to the distribution of manufactured gas, which is scarce and produced on a daily basis. They are not prepared to manage the distribution of natural gas brought by pipelines or LNG cargoes in huge quantities. They need to overcome a big cultural gap between the management of scarcity and the management of an abundant and steady supply by developing marketing and sales policies. They will also have to improve relations with customers to provide a broader range of services.

Third, the conversion of a city-gas network and gas appliances is a mammoth programme that will take time, money and most importantly, a well-defined standard approach throughout the nation. Finally, ensuring gas supply security at LDC level needs a sophisticated system of management and co-ordination in supply modulation, which will require co-ordination with gas transmission companies who manage storage.

Key recommendations include:

- Improving the financial health of the local gas distribution companies is an urgent and serious task for the development of the gas market. Current gas pricing practices need to be rationalised and a new tariff structure developed on the basis of sound economic principles. Only a financially sound distribution sector can provide the creditworthiness needed for long-term gas supply projects.
- Encourage LDCs to cross the existing cultural gap between manufactured gas and natural gas by developing an active gas marketing policy and programme. This must be based on serious market surveys of the current and future needs of consumers.
- Further open the gas distribution sector to foreign investment in order to learn from established gas management practices.
- Take appropriate measures to assess and address as appropriate the asymmetry in market strength of the numerous local distribution companies, the few large national producers, the gas appliance manufacturers and the electrical appliance manufacturers.
- Create a national promotion effort for gas conversion, to be placed under the Ministry of Construction or the China Gas Association, to define and promote rules and safety standards for gas conversion work.
- Oblige local distribution companies to define a contractual quality of gas with their customers.
- Encourage close co-operation between gas appliance manufacturers and distribution companies in order to help gas market development and accelerate gas conversion work.

Gas pricing and taxation (Chapter 6)

To a large extent, the size and shape of a country's gas industry is determined by its pricing policy. Natural gas pricing and taxation are thus critically important for market development. They should encourage both gas consumption, by providing incentives for energy users to switch to gas, and gas production, by giving investors a fair and reasonable return. They should ensure the viability of each link in the gas chain.

Traditionally, China has used a system that allocates gas volumes and sets the prices for both producers and consumers. Over the past few years, in line with its goal to encourage gas production, it has implemented a series of gas pricing reforms, including the introduction of a new pricing regime based on a cost-plus formula. Today, final gas prices are high by international standards.

China's current pricing system raises a number of other major problems: it is not cost-reflective and does not encourage market development, for example, by imposing progressive rates on higher consumption. The government-set or guided uniform well-head prices do not take into account the real cost of individual fields or reflect the changing demand/supply situation. The cost-plus approach does not encourage cost-reduction or efficiency improvement; gas prices are set on the basis of volume, not calorific value. Furthermore, the pricing system is opaque and lacks predictability, transparency and stability. It needs radical change.

Reform could start with the adoption of a new pricing approach that would encourage consumption. This should involve the immediate decontrol of well-head prices for new gas production, and a phasing out of price and volume setting for existing production. The decontrol of wholesale prices would pave the way for buyers and sellers to negotiate prices on the basis of the net-back market value of gas in relation to competing fuels.

Key recommendations on gas pricing include:

- Define a timetable for the transition of all gas prices and volumes to be freely agreed by market participants, subject to protection of captive customers and prevention of misuse of market power.
- Encourage co-operation between its pricing and fiscal authorities and energy policy institutions to work out a pricing and taxation regime that would better reflect the energy policy objectives of the country.
- Remove – in a phased manner – all controls on gas prices at the well-head and city-gate, and to large end-users directly off high-pressure transmission pipelines. During the transition ensure the end-use competitiveness of gas by adopting a net-back-pricing methodology based on the market replacement value to gradually replace the current cost-plus formula.
- Co-ordinate the timetable for phasing out price controls with other policy actions such as the commercialisation of distribution grids, the further privatisation of state-owned companies and a stronger involvement of private investors in the gas industry.

On gas taxation, China's current fiscal system applicable to the gas industry reveals some problem areas. First, the production-type of VAT[4] does not allow for tax refunds on the purchase of capital goods and penalises capital intensive industries such as natural gas. Second, China's upstream fiscal regime does not take into account project profitability or resources quality, and it imposes too little tax on the most profitable projects and too much on the least profitable ones. Third, the implementation process leaves much room for local authorities to impose fees and charges on gas projects. Tax burdens in the midstream and downstream sectors are high,

4 There are three types of VAT in the world: production-type, income-type and consumption-type. At present, most countries adopt the consumption-type VAT and apply it to all goods and most services. China has adopted a production-type VAT, which applies to all industrial production, commercial sales, imports of goods, provision of processing services and industrial repairs and replacement. Under a production-type VAT, the tax paid on purchases of fixed assets necessary for production cannot be credited against VAT charged on sales of products. Source: OECD, 2002, *China in the World Economy*. p.635.

contributing to high consumer prices. Under the WTO agreement, China lowered the import tax on crude oil and many oil products, but the 6 per cent tax on LNG imports remains unchanged. The gas taxation regime needs to be reformed so that it can serve as a powerful tool to encourage both production and consumer market development.

Key recommendations on gas taxation include:

- Implement a comprehensive reform of the fiscal regime for natural gas to lower the overall burden of taxation on gas supply, to improve the market position of gas relative to other fuels, especially coal, and to reflect its environmental advantages and stimulate switching to gas.
- In the midstream and downstream, review and restructure the current system of energy taxation so that end-user prices better reflect the environmental externalities of energy use. Natural gas taxes should be set at zero or at a significantly lower level on an energy equivalent basis than taxes on coal and oil products, reflecting the lower emissions from gas.
- Consider reducing or removing the high taxes on imports of LNG, pipeline materials and equipment, which significantly raise the cost of building transmission lines and local distribution networks. The 6 per cent tax on imports of LNG and the additional tax applied to the standard rate of VAT undermine the economics of LNG projects.
- Restructure the upstream tax structure in favour of taxing profits, to take into account local differences in geological and economic conditions. Remove any differences in tax treatment between domestic and foreign companies. Periodically review upstream fiscal terms to ensure that they remain internationally competitive and are consistently applied to all industry participants.
- Boost investments into all parts of the gas chain, by exempting gas-related investment from VAT (in anticipation of VAT reform). Consider tax credits, e.g. by extra depreciation for gas-related investment.
- Improve the co-ordination between central government and provincial authorities in applying taxes, to avoid situations in which provincial tax policies undermine national policy goals by collecting additional taxes and fees.

Long distance gas pipelines (Chapter 7)

Building long-distance pipelines is an important challenge in all parts of the world. It is particularly so in an emerging gas market such as China. The two main preconditions are a sufficiently large paying demand for competitive gas and adequate gas reserves. Once these preconditions are fulfilled, the most critical success factors are the alignment of interests of all major players and a well-balanced risk-reward allocation among the players.

The West-East Pipeline project has been pushed by many factors, one of which is the need to exploit gas resources in the Tarim basin. But if not carefully managed, the pipeline will bring gas to the east where there is no market. This has already happened with the Ordos-Beijing and the Sebei-Lanzhou pipelines. Market development and gas resource utilisation must proceed in tandem. The key short-term issue that will determine the success of the WEP is the timely and effective development of the downstream gas market. But long-term issues, such as the impact of the politically-induced WEP on the future gas industry structure and the future introduction of competition both upstream and downstream, need particular attention.

Beyond purely domestic long-distance pipelines, China will explore the option of building cross-border gas pipelines from Russia, perhaps also acting as a transit country for such pipelines. The realisation of these projects will require that they be governed by international rules on cross-border energy trade, investment and transit.

Key recommendations include:

- Define an enabling policy framework for gas infrastructure building, through a clear and reliable national gas policy. The government should leave pipeline construction and operation issues to project sponsors and operators, and focus on long-term policy issues that any specific pipeline project may raise. Its role is to facilitate the building of long-distance gas pipelines by creating a clear, transparent and predictable framework for private investment that would mitigate the high-risks inherent in any large-scale project.
- Take active measures to encourage downstream gas market development by private investors as a means of supporting gas pipeline projects.
- On the West-East Gas Pipeline project:
    - Facilitate downstream gas market development by encouraging gas consumption, especially by large anchor projects such as power stations, by providing incentives, reducing project approval burdens, and by backing the long-term gas purchase commitments of off-takers based on realistic demand evaluations, etc.
    - Pay attention to long-term structure and regulatory issues in defining the framework conditions for this particular project and make sure that short-term project decisions do not jeopardise the long-term goals of gas market development.
    - Correlate more closely the building of the western section of the pipeline with the downstream market development in the east.
    - Liberalise price controls at wholesale level (both at well-head and city-gate) and encourage net-back gas pricing (both are necessary conditions for take-or-pay contracts). Continue cost or rate-of-return regulation for the pipeline itself.
    - Set clear and stable fiscal rules (taxes and concession fees) over the project's lifespan, by taking due consideration of the risk-reward balance at different stages of the project.
- On gas import pipelines from Russia, the government should strengthen co-operation with all of the countries concerned, prepare the market by conducting a serious and independent market study, adhere with other countries to international rules on investment and transit, and create conditions conducive to the future construction of the pipelines.

LNG import projects (Chapter 8)

The construction of the first LNG terminal in Guandong has opened the door for a local gas market based on LNG along China's East Coast. LNG supply is widely available in the region to accommodate any future growth in China and in the Asia-Pacific region. LNG projects face a number of issues common to other large-scale gas pipelines, in particular, downstream market development. Like pipeline projects, the critical factor for the successful development of the LNG market is the alignment of interests among project promoters, upstream producers, downstream gas users, local and central authorities.

Similar to the WEP, the Guangdong project needs to tackle a number of challenges. In the longer term, the key to the development of a successful LNG market in China is to replicate the positive experiences learned from the Guangdong pilot project and to obtain central government support for other projects. Policy-makers will need to bear in mind several long-term issues such as open access to LNG terminal and pipelines.

Key recommendations include:

- Encourage the development of LNG markets through active leadership in structuring LNG-based gas infrastructure projects, providing incentives that promote growth in gas demand, backing gas off-takers in their long-term purchase commitments, and reducing uncertainties caused by power sector reform.
- In the context of designing an overall legal and regulatory framework for the entire natural gas industry, establish clear procedures for the approval and licensing of LNG projects, with particular attention to the future needs of open access to LNG infrastructure.
- Clearly indicate the intention to allow third-party access to the existing LNG terminal and related facilities at a defined future date. The institutional structure should enable long-term competition between gas suppliers through open access to on-shore pipelines and import terminals as the market matures. This kind of competition cannot be effectively introduced, however, until the market is sufficiently well established.
- Draw up and enforce appropriate technical, safety and environmental standards for LNG importation and regasification.

Gas infrastructure financing (Chapter 9)

The expansion of China's gas market requires a significant volume of capital investment in infrastructure projects. The WEP project alone will need US$18 billion of investment in upstream, pipeline and downstream activities. As a rule of thumb, each additional cubic metre of gas market will cost about US$1 to develop. Within the next five years, China needs some $40 billion of investment in its gas sector to meet its forecasts for gas demand. The amount is much larger for the period beyond. The critical issue is not the availability of finance, but the cost of financing these investments. Investment can be realised only when a financing structure for each individual project has been successfully negotiated.

Financing gas infrastructure projects (pipelines and LNG) has a number of specific features such as the need for long-term commitment from both gas producers and gas off-takers. The particular circumstances of pipeline projects in China have made it difficult for them to be financed through limited-recourse project financing. Further downstream, financing urban gas distribution networks is another important challenge. The key success factor for financing throughout is a balanced risk allocation among the actors in the gas chain, which allows investment return to be commensurate with the risks. Also, the financing structure of large projects such as the WEP will have important implications for the evolution of the entire natural gas industry structure.

Key recommendations include:

- Create conditions that would facilitate the commercial financing of gas infrastructure projects and take active measures to help investors reduce investment risks. This could include, but is not limited to:
  - Providing some sort of credit backing to downstream off-takers to make sure that they will honour long-term off-take agreements. This would enhance the bankability of the whole gas chain from upstream exploration to the city-gate.
  - Recognising the environmental benefits of gas, providing subsidies, preferential tax exemptions or preferential land lease fees to gas infrastructure ventures so that they can offer a competitive price relative to other sources of fuel, thus improving their economic sustainability and helping the gas market to grow.
- Increase the availability of domestic financing resources. This could include:
  - Creating a national, uniform regulatory system to create and regulate a municipal bond market.
  - Continuing to broaden and deepen the banking system reform to allocate lending on a commercial rather than a political basis.
- Pay attention to the regulatory implications of the commercial structure of any large gas infrastructure projects.

Foreign investment (Chapter 10)

Foreign investment is highly desirable if China is to achieve its stated objective of gas market development. In addition to capital, foreign investors will bring technology, know-how and managerial skills, to complement those available in China today. Through the latest revision of the guidelines and catalogue for foreign investment, the government has expanded the scope for foreign investment in the natural gas sector. Foreign investment is permitted in gas distribution but with restrictions. It is encouraged in gas exploration and production activities, in pipeline construction, as well as in building and operating gas-fired power plants.

Beyond this positive development, China still lacks a systematic approach to foreign investment in natural gas. Current practice is based on a "project-by-project" approach. Among international investors, there is a need to level the playing field somewhat between large and small companies. It will also be necessary to define gas investment policy as part of the country's long-term gas policy.

Key recommendations include:

- Respect the internationally commercial principles that underline any investment decision by foreign companies. These principles include long-term legal and fiscal stability, freedom in commercial decision-making, administrative neutrality, absence of political intervention, regulatory transparency, and respect of contract sanctity.
- In line with the commitments to the WTO, further improve general conditions for foreign

investment in China and those in its gas sector in particular, by increasing the transparency of the regulatory and approval process and reducing project approval procedures.

- Move beyond the current "project-by-project" approach by developing a coherent policy framework for investment in gas infrastructure projects as part of the national gas policy.
- Open further the gas distribution sector to foreign investment and improve conditions for investment in that sector.

Structure and regulation (Chapter 11)

As part of the oil industry, China's gas industry has evolved a long way from a single government ministry in the 1970s to a situation today where three national oil companies, all partially privatised, enjoy a quasi-monopoly in their respective geographical areas. The key challenge is to recognise that oil and gas are quite different businesses and to reconcile the requirement for investment protection with the need for introducing competition to improve efficiency. Important additional restructuring may be premature given that China's oil and gas industry has just gone through a major regrouping since 1998. But there is a need to remove the structural causes of market discrimination. A legal framework for the gas industry is needed to fill the current gap in mid- and downstream gas legislation. Actions are also needed to clarify the relationship between policy-making, regulation and ownership of state-owned companies.

A main conclusion of this study is that China's natural gas market is still in its infancy. Consequently, it needs a relatively simple regulatory structure that would allow its rapid development and provide an eventual transition to a competitive industry in the longer-term. Regulations for health, safety and environmental impacts as well as technical standards should be established as soon as possible.

A very important task for oil and gas sector policy-makers is the complete and effective removal of policy-making and regulatory responsibilities from state-owned companies. This and the increased complexity of the energy system call for strengthened government capacity in policy-making and regulation. One way of achieving this is the creation of a new energy department within the central administration, to be equipped with adequate resources, as well as appropriate analytic and regulatory tools.

Key recommendations include:

- Publish a white paper on gas policy and prepare a legal framework on natural gas as suggested earlier.
- Effectively and completely remove policy-making and regulatory functions from state-owned energy companies.
- Establish a specialist national energy department, initially responsible for both energy policy-making and industry regulation.
- Establish, in the medium term, a national regulatory agency for the gas industry, with sufficient resources, accurate data and adequate analytical ability.
- Put in place as soon as possible a set of regulations on health, safety and environmental impacts as well as technical standards for the gas industry.

- Focus on creating conditions for competition to build pipelines while setting the stage for the future introduction of competition in using them.
- Develop a model concession agreement for local gas distribution based on the experience of a few cities.
- Allow exclusive rights for companies to use their own gas transmission and LNG facilities, and exclusive supply *via* local distribution networks for captive customers, each for a limited duration.

ENERGY POLICY CHALLENGES

The recommendations provided above are numerous, but by no means exhaustive. They do not provide a blueprint for China to follow, but describe an important set of issues that the Chinese government and gas industry players need to address seriously in developing China's gas market.

Many of the issues raised in the report go far beyond the gas sector. They are indeed very strongly related to the country's overall energy policy. This leads the IEA to conclude that the development of China's natural gas market raises broader energy policy challenges, not confined to the gas industry:

- First, the government's objective of raising the share of natural gas in the country's energy mix is an energy policy objective, rather than an objective that concerns the gas industry alone. Gas market development concerns a number of sectors including electricity, coal, finance, investment, and the environment. It also involves many players from outside the oil and gas circle, not least those in power companies, pricing and taxation authorities, urban planning, financial communities and environmental agencies.
- Second, the penetration of natural gas in China's energy system encounters the same types of problems as other clean energy sources and technologies, such as renewables and clean coal technologies. They concern the adjustment of the whole energy system, which is not an easy task, given the rigidities of energy infrastructure, and the inertia of energy demand patterns.
- Third, competition between gas and other energy sources, in particular coal, also raises important energy policy questions regarding the role of individual energy forms in the country's energy system. Power generation, which is assumed will be one of the largest gas consuming sectors in the future, relates to the core of the country's energy policy debate: is gas-fired power generation a long-term option to pursue? How to design the structural reform of the power sector in a way that will minimise the negative impacts on gas-fired generation and other clean power sources?
- Fourth, urban gas distribution touches upon a number of important questions related to utility regulation, to some degree similar to the supply of electricity and water.
- Fifth, natural gas pricing forms part of the country's energy pricing policies.
- Last but not least, the role of natural gas in reducing energy-related environmental pollution also calls upon the country's overall energy policy decisions on energy-environmental issues.

All of these factors point to a very important conclusion: the natural gas market cannot be developed in the absence of a well-defined national energy policy, and many of the challenges that are described in this report are indeed energy policy challenges for the whole country. A sound gas policy is dependent on a coherent national energy policy. Therefore, beyond the gas sector, there is a need for the Chinese government to work out an integrated national energy policy with particular attention to addressing energy-related environmental issues. This could be achieved on the basis of the 2001-2005 Five-Year Plans for the energy sector and related energy industries.

Natural gas market development takes time and needs capital, technology, know-how and tireless efforts applied in a systematic manner. The challenge is particularly daunting for China, which wishes to achieve a level of gas market development that took 100 years for the United States and 50 years for Europe, within a much shorter timeframe but under much poorer gas resource conditions. It is not impossible. The time taken could indeed be shorter if China could effectively adopt best practices and thus avoid the pitfalls.

ECONOMIC, ENERGY AND ENVIRONMENTAL CONTEXT

Highlights:

- *After two decades of sustained growth, China today is confronting new challenges both internally – by narrowing the regional development gap, and externally – by meeting the obligations of the World Trade Organisation.*
- *The key priority for China's energy sector development is to increase the share of cleaner energy sources in the country's energy supply mix. Reducing China's serious environmental pollution also calls for controlling the use of coal. These two factors, together with improved living standards for the population, provide a favourable context for the development of China's natural gas market.*

This chapter describes China's economic, energy and environmental context for the development of its natural gas industry and market.

THE ECONOMIC CONTEXT

A stage of "small rich"

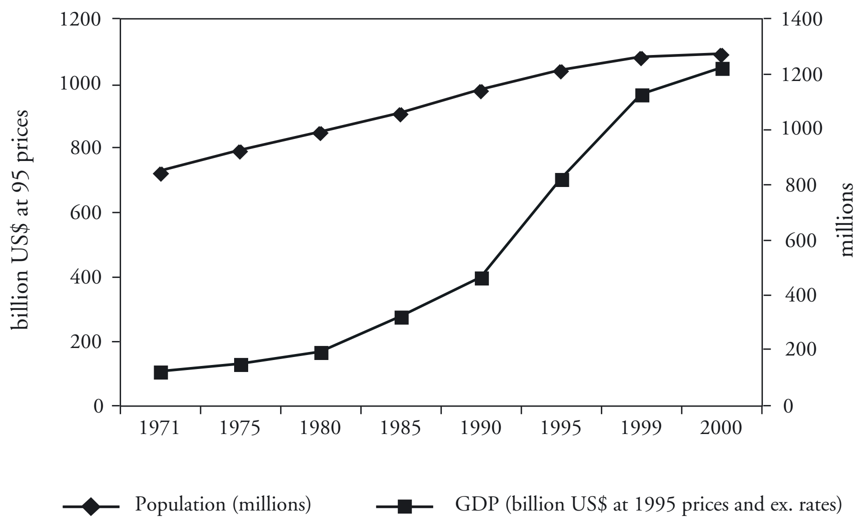
With a population of 1,266 million in 2000, 36% of whom live in urban areas, China is the most populous country in the world. After two decades of sustained economic growth, China's GDP reached 8,940 billion RMB (US$1,080 billion) in 2000, around six times the level of 1980. According to the World Bank, China has lifted 200 million people out of poverty over this 20-year period, the best performance that history has ever seen in any single country.

Important changes also occurred in the structure of the economy: the agricultural sector, which contributed 30% of the GDP in 1980, accounted only for 16% in 2000. The service sector grew from 21% in 1980 to 33% twenty years later. Industry's share also expanded by two percentage points during the same period.

At 6,902 RMB (or US$830) per head in 2000, the GDP/capita more than quadrupled the level of 1980, but it remains low compared to OECD countries. Even in terms of purchasing power parity, the per capita GDP, at US$3,800, is still a fraction of the OECD average (US$19,000/capita). However, for many Chinese, this level of development is already at "Xiao Kang", a Chinese term which can be literally translated as "small rich", meaning a stage of development at which people enjoy more than just meeting the basic living requirements.

Figure 1.1

China's GDP and Population (1971-2000)



Source: IEA.

Huge potential for growth exists, especially in the mid and western parts of the country, and China continues to outpace the world's average growth rate by several percentage points. Official sources indicate that China's GDP grew by 7.3% in 2001 and 7.9% during the first six months of 2002. The main driving factor is the increase in domestic demand, including increased domestic investment and private consumption. The official growth target for the period 2001-2005, as set by the 10th Five-Year Plan, is 7% per year.

Regional disparities

The national average of GDP per capita hides, however, important disparities between regions within the country. The per capita GDP of Shanghai (RMB30,805 in 1999) is nearly 12 times that of Guizhou (RMB2,463) in the south-west of the country. The eastern region, which accounts for 40% of the country's total population, makes 60% of the GDP. Its per capita GDP is twice that of the central region and three times that of the western region[1]. Important inequalities between regions also exist in terms of education, health care, economic structure, infrastructure development, foreign direct investment (FDI) flow and overall human development index. In addition, there exits an important urban/rural divide in all Chinese regions, and the development gap is widening.

1 For planning purposes, China is divided into three regions: The *Eastern region* covers Beijing, Tianjin, Hebei, Liaoning, Shanghai, Zhejiang, Jiangsu, Fujian, Shangdong, Guangdong, Guangxi, and Hainan. The *Central region* includes Shanxi, Inner Mongolia, Jilin, Heilongjiang, Anhui, Jiangxi, Henan, Hubei, and Hunan. The *Western region* takes in Chongqing, Sichuan, Guizhou, Yunnan, Tibet, Shaanxi, Gansu, Qinghai, Ningxia, and Xinjiang.

Developing the western region

To reduce the growing economic gap between the western/central regions and the more prosperous eastern coastal provinces (which threatens the country's unity, social stability, and national security) the government has launched a vast campaign of "Developing the West".

The campaign targets twelve provinces (including one direct administrative city and four autonomous regions). They basically include the western region as defined by Chinese planning terminology, plus Inner Mongolia in the central region, and Guangxi province in the eastern region. The area covers about 60% of the country's land and involves 25% of its total population (Figure 1.2).

Figure 1.2

Areas Covered by the Western Regional Development Campaign

In January 2000, the State Council established a Leading Group for Western Regional Development, headed by Premier Zhu Rongji. The leading group defined the following priorities for the Western regional development campaign:

- Acceleration of basic infrastructure building;
- Strengthening ecological and environmental protection;
- Adjusting economic structure;
- Developing science and technology, and building human resources through education;
- Further reform and opening to the outside.

Major infrastructure projects have been proposed as part of the campaign. They include:

- The 4,000 km West-East gas transmission pipeline, which will transport 12 billion cubic metres per annum (bcm/a) of natural gas from the Tarim basin in Xinjiang to Shanghai (see more details in Chapter 7).
- The West-East electricity transmission corridors, which will bring electricity from hydro and coal-rich provinces in the west to power-starved provinces in the east:
    - The North Corridor would bring electricity from coal-fired plants in Shanxi, Shaanxi and the west of Inner Mongolia, and hydropower from upstream on the Yellow River to Beijing, Tianjing, Tangshan, Hebei and Shandong. The target for 2005 is to form a power transmission capacity of 5 GW.
    - The Mid Corridor would bring hydropower from the Yangtse River and its upstream tributaries to central China and east China regions. The main project is the Three Gorges hydropower station, which is scheduled to be completed by 2009. The project aims to deliver 17 GW of power, with 6 GW destined for east China. Another large scale of 12 GW of hydropower capacity is planned as part of the Mid Corridor.
    - The South Corridor would transmit electricity from hydropower stations in Yunnan, Guizhou and Guangxi and from coal-mine-mouth power stations in Yunnan and Guizhou to Guangdong. The total capacity during the 10th Five-Year Plan (FYP) period would be 16.9 GW (with 10 GW targeted for Guangdong) and 5,400 km of high-voltage (500kV) transmission line. Total investment would exceed RMB 110 billion.
- The Qinghai-Tibet railway: the 1,110 km railway would connect Golmud in Qinghai province with Lhasa in Tibet, most of which runs at an altitude above 4,000 meters. The project started in June 2001 and is scheduled to be completed by June 2007. The total investment is RMB 26.2 billion.

In addition to these major national projects, there are also numerous projects in the provinces involved for the construction of roads, railways, airports, electricity grids, telecommunications and water resources.

WTO membership

On 11th November 2001, China signed the WTO entry agreement in Doha, after the 4th WTO Ministerial meeting unanimously approved Chinese membership the previous day. Its membership in this organisation became effective on 11 December 2001, i.e. 30 days after the signing of the agreement. This completed a 15-year-long process for China's accession to this international trade body.

WTO membership is likely to promote broad trade and investment liberalisation, increase competition in domestic markets, and promote a better legal framework for business operations. It is also expected to boost the otherwise stagnating economic reform process and to help the central government to break down various vested interests at different levels of the administration.

To comply with WTO rules, China has reportedly been busy revising laws, regulations and other administrative codes that may be incompatible with its commitments.

Status of reform and policy challenges

As denoted by the OECD's major study[2] of the domestic policy challenges facing China after WTO membership, China's accession to the WTO marks an important milestone along the reform path China has been following for more than twenty years, rather than a new direction. While acknowledging the impressive progress China has made in transforming its economy during the reform era, the OECD study also pointed out that the important engines that have driven China's growth in the past are losing their dynamism[3] and that trade and investment liberalisation through WTO alone is unlikely to solve the basic problems now impeding China's economic development. The OECD study also provides a number of recommendations (Box 1.1).

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2 OECD, 2002, *China in the World Economy: The domestic policy challenges.* Paris, 813p.

3 Key problems identified in the OECD study include:

- Obstacles to resource utilisation in the rural economy;
- Structural impediments to further industry development, with a vicious cycle formed by weak corporate government, inefficient operations, poor performance, low profits and high debts, restructuring difficulty and government interference;
- Growing constraints from the financial system, with a vicious cycle between bank and enterprise problems;
- Emerging weakness in macroeconomic performance; and
- Growing imbalances in regional development.

Box 1.1

OECD Recommendations on Meeting China's Domestic Policy Challenges after WTO

Improving the utilisation of China's resources by:

- Raising labour utilisation;
- Making better use of land and environmental resources;
- Bolstering the capacity of the business sector to productively employ resources;
- Improving the effectiveness of the financial system; and
- Achieving better integration among China's regions.

Strengthening the institutional frameworks for market functioning by:

- Strengthening enterprise governance;
- Reforming property rights and insolvency mechanisms;
- Improving the competition framework;
- Developing financial regulatory and supervisory capabilities; and
- Improving the enforcement capacity of the judicial system.

Improving the government's capabilities to support economic development by:

- Bolstering public finances;
- Reforming central-local government fiscal relations;
- Improving the flexibility of macroeconomic policy instruments; and
- Creating the framework for a market-based regulatory system.

Source: OECD, 2002, *China in the World Economy: The domestic policy challenges*. Paris. pp 25-48.

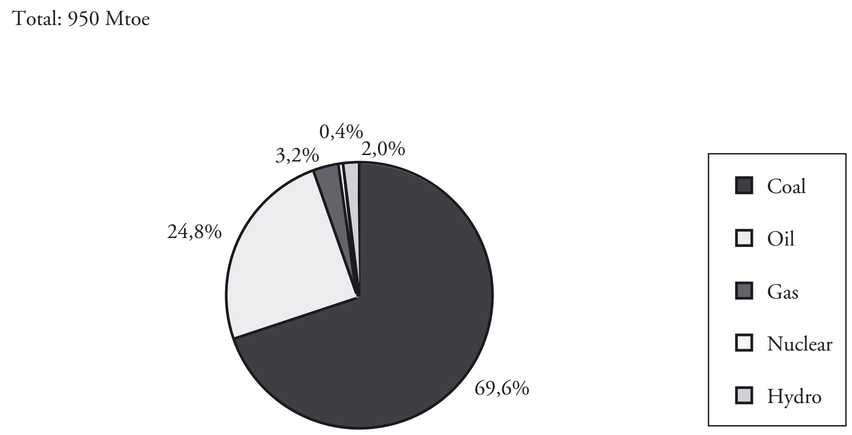
THE ENERGY SITUATION

China is the world's second largest energy producer and consumer after the United States. It also ranks second in CO_2 emissions, but is the largest SO_2 emitter. Including non-commercial energies such as fuel wood and combustible wastes, China's total primary energy supply (TPES) in 2000 was 1,106 million tonnes of oil equivalent (mtoe), 61% of which was made from coal. However, excluding non-commercial energies, coal provides 70% of the country's TPES (Figure 1.3). China is the world's largest coal producer and consumer. The total installed power generating capacity was 319 GW by end 2000, around 70% of which is fuelled by coal.

Industry and residential sectors are two of the most important energy consumers, accounting respectively for 40% and 38% of the country's total final energy consumption (Figure 1.4).

Figure 1.3

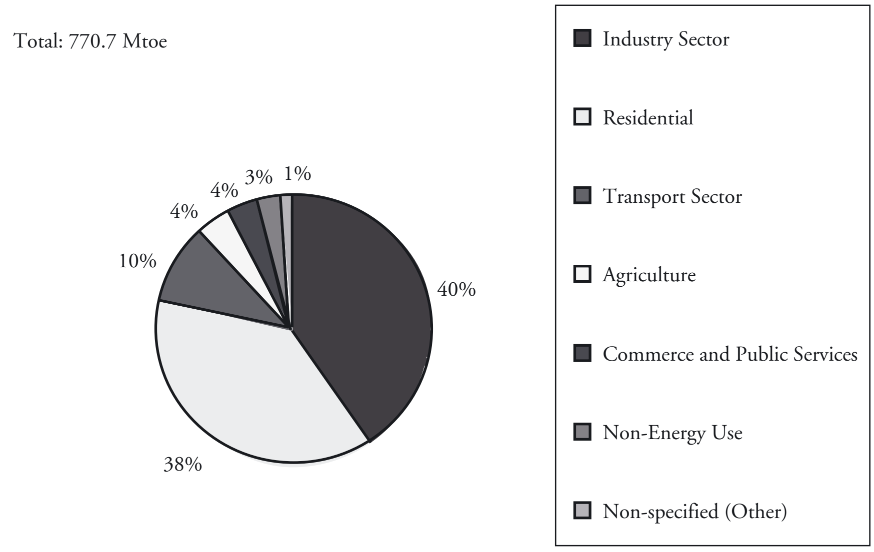
Composition of China's Commercial Primary Energy Supply in 2000



Source: IEA.

Figure 1.4

Final Energy Consumption by Sector in 2000



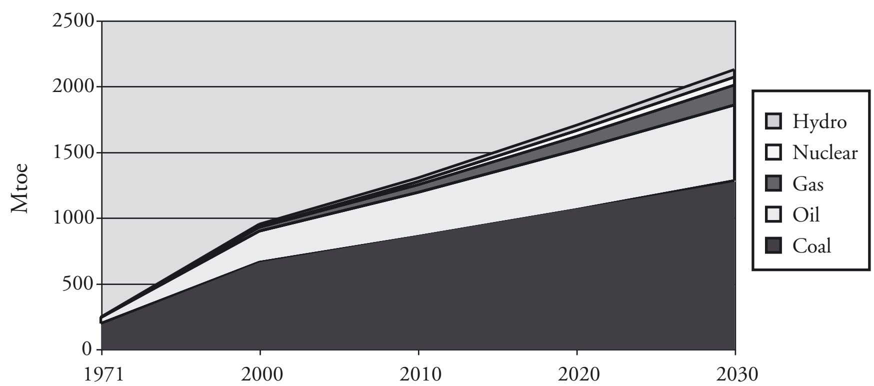
Source: IEA.

The 2002 edition of the IEA's *World Energy Outlook* projects that China's primary commercial energy demand will grow by 2.7% per year from 2000 to 2030 (Figure 1.5). This growth is much slower than in the past decade, but is still faster than in most other regions and countries and leads to nearly a doubling of demand over the projection period. The 1,182 Mtoe increase in demand represents about a fifth of the total increase in worldwide demand between 2000 and 2030.

The share of coal in China's primary energy supply will drop from 70% in 2000 to 60% in 2030, while that of each other fuel increases. Coal remains the dominant fuel in power generation, but is increasingly replaced by other fuels in industry and households. Nonetheless, China's coal demand will continue to increase and that increase will account for around 50% of the world's total incremental demand for coal over the next 30 years. Primary consumption of oil grows steadily, driven mainly by transport demand and to a lesser extent by industry. Some 16% of the increase in world oil demand comes from China. Natural gas use expands even more rapidly, but from a much smaller base. Although gas' share in primary supply nearly doubles, it still only meets about 7% of the country's energy needs in 2030. Likewise, nuclear power, which plays a very small role in China's energy supply today, surges by 9.3% per year, but finishes with a mere 3% share of total energy.

Figure 1.5

Total Primary Energy Supply in China from 1971 to 2030



Source: IEA, 2002, *World Energy Outlook.*

Key energy sector issues

For many decades, the lack of adequate energy supply was the bottleneck of economic development in China. This problem has been eased to a great extent. Today, the general situation of the energy sector can be characterised by:

- The over-supply of coal: China produced a record 1,400 million tonnes of coal in 1996. Since then, coal production has been decreasing. Reasons for the drop in coal demand include the shift to higher quality coal, structural changes in the economy towards light industries that demand high quality fuels, stricter environmental regulations that limit the use of coal, shutting down of small coal-fired power generators, and the bankruptcy of some state-owned enterprises that are big coal users. From the supply side, since 1998, the government has been closing down small and illegal coal mines that are unsafe and polluting. By the end of 2000, the government claimed to have closed down 47,000 small mines[4], which represent a production reduction of 350 million tonnes.

- The shortage in oil and gas: China became a net oil importer in 1993 and today imports around one third of its oil needs. Natural gas supply is limited by the transportation infrastructure.
- The relatively balanced supply of electricity: During the period 1996-2000, China added 100 GW of power generating capacity. This has eased the overall situation of supply shortage that prevailed in the early 1990s. Although today supply meets demand in general, some provinces are starting to experience shortages, especially during the summer peak hours.

The most important problem facing China in its energy sector today is probably the serious environmental problem caused by a coal-dominated energy supply, the low efficiency of coal combustion, and the lack of depollution facilities in coal use[5]. Two other key energy sector issues include the security of energy supply related to the increased dependency on imported oil and the reform of the energy industry and markets. In addition, China's membership in the WTO is also likely to pose challenges to its energy industries (Box 1.2).

Box 1.2

Impacts of China's WTO Membership on its Oil and Gas Sector

The impacts of WTO membership on China's energy sector, though difficult to assess at the moment, could be grouped as direct and indirect, quantitative and qualitative.

Direct and quantitative impacts are mainly the result of tariff and quota concessions on the imports of energy products. They include:

- Drop of crude oil tariff from 16 yuan/tonne to zero, effective from January 1, 2002.
- Drop of gasoline tariff from 9% to 5%, effective from January 1, 2002.
- Drop of lubricants tariff from 9% to 6%, effective from January 1, 2002.
- Drop of natural gas (in gas form) from 6% to zero, effective from January 1, 2002.

(The import tariffs of a number of other energy products will remain unchanged: the tariff for kerosene and jet fuel stays at 9%; and the tariff for diesel, fuel oil, naphtha and LNG remains at 6%.)

4 Chinese sources indicate, however, that many of these closed mines continue to operate illegally.
5 Energy-related environmental problems are described in more detail in section 3 of this chapter.

Concessions on import quotas and licenses include:

- Non-state trading of crude oil and products[6]: for crude oil, non-state traders will be allowed to import 8.28 million tonnes of crude in 2002 and the volume will increase annually by 15% for 10 years. The import quota for crude oil will be abolished on 1st January 2006. For oil products, private companies will be allowed to import 4.6 million tonnes in 2002 and the volume will also increase at an annual rate of 15%. The import quota for oil products will be eliminated on January 1, 2004.
- Opening up of retail and wholesale businesses: foreign investors will be allowed to conduct retail services of oil products three years after China's WTO accession, and wholesale services of crude oil, products and fertilizer five years after accession.

The tariff reduction on crude oil and products, the permission for non-state trading, the elimination of quotas and the opening up of the wholesale and retail sectors will remove the protection that Chinese oil and gas companies have enjoyed so far. They will be exposed to more international competition for crude oil and oil products as well as for services in the retail sector. These measures are likely to increase the efficiency of China's oil and gas industries. China's domestic prices will follow international fluctuations more closely, and Chinese influence on international markets could be greater.

The **indirect and qualitative impacts** could be even more significant than the direct and quantitative impacts. One example of indirect impact is the impact of automobile import tariff reduction on oil demand. Under the WTO commitment, China will reduce the tariff on car imports from the pre-WTO level of 80-100% to 25% in 2006 and the tariff on automobile parts to an average rate of 10% by 2006. All licenses and quotas for automobile and key parts will be eliminated by January 1, 2005. This will significantly reduce car purchase cost and increase choices in the domestic market, which will lead to an increase in car ownership and hence in oil demand in China.

Another example of indirect impact is the import quota concession on fertilizer. Under the WTO commitment, China will allow the import of 1.3 million tonnes of urea at a reduced tariff rate of 4% compared to a normal tariff of 50%. This volume of import at reduced tariff will gradually increase to 3.3 million tonnes by 2006. The impact of importing low-tariff urea will put price and market pressure on domestic producers. Five years after accession, foreign firms will be allowed to retail fertilizers. This will not only affect the domestic fertilizer market, but also the natural gas market, as fertilizer production accounts for 40% of China's total consumption of natural gas.

The qualitative impact will not only affect energy trade and consumption, but most significantly foreign investment in China's energy sector. It could be expected that under the WTO principles of non-discrimination, national treatment and transparency, the environment

6 Crude oil and most oil products remain under state import and export control in China. Four companies are the designated state importers of crude and oil products: Sinochem, Unipec, ChinaOil and Zhuhai Zhenrong. Three companies are the designated state exporters of crude and oil products: Sinochem, Unipec and ChinaOil. Non-state trading refers to trade that takes place outside these state designated companies.

for foreign investment could be greatly improved. Also, under the principle of national treatment, the different upstream fiscal regimes for foreign and domestic oil companies are likely to be harmonised. WTO membership will also provide momentum for China to continue the reform of state-owned enterprises, including those in the energy sector. It may also provide more opportunities for mergers and acquisitions between Chinese companies, as well as between Chinese and international energy companies.

Source: IEA analysis.

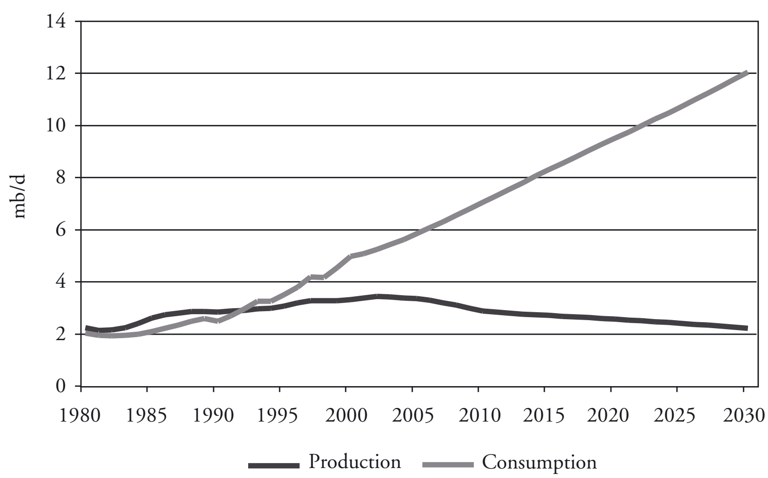
Oil security

With total oil demand at 4.8 million barrels per day (mb/d) or 240 million tonnes per year (mt/y) in 2000, China is the world's third largest oil consumer after the United States and Japan. A net oil importer since 1993, China's oil imports have grown rapidly, reaching an average of 1.5 mb/d (or 75 mt/y) today, making China the largest oil importer outside the OECD. Chinese oil demand grew by 7% in 2000, three times the global growth rate. This oil demand growth is expected to slow down a little, but will remain one of the fastest in the world.

According to the 2002 edition of the IEA *World Energy Outlook*, Chinese oil demand will reach 12mb/d in 2030, more than doubling its level of 2000. Most of this additional oil will have to be imported. Net oil imports will rise from 1.5 mb/d in 2000 to 4.0 mb/d in 2010 and 9.7 mb/d in 2030. The share of imports in total oil supply will reach 84% in 2030 compared to only 31% in 2000 (Figure 1.6).

Figure 1.6

China's Growing Gap between Oil Demand and Production



Source: IEA, 2002, *World Energy Outlook.*

With the country already importing one third of its oil needs and oil dependence still growing quickly, Chinese policy-makers are paying a great deal of attention to the country's energy security. The IEA study, *China's Worldwide Quest for Energy Security*, published in March 2000, summarised the efforts that are being pursued by the Chinese government in relation to its country's energy security. They include: *i)* reforms of its domestic energy industries, *ii)* maximum development of its domestic resources, *iii)* seeking of foreign technology and investment, *iv)* diversifying overseas suppliers, *v)* building strategic oil reserves, *vi)* investing overseas in upstream activities, and *vii)* fostering political and economic links with major producing countries.

For the first time, energy security is included as one of the central elements in the country's 10th Five-Year Plan (2001-2005) for the energy sector. Emergency oil stocks (or strategic oil reserves) like those held in IEA countries, are now formally included in the government's energy agenda.

In addition to building emergency oil stocks, the government is also aggressively pursuing other energy security measures. They include:

- adjustment of energy supply structure to increase the share of cleaner energy sources, especially cleaner coal products and technologies;
- energy diversification to increase the share of natural gas and renewables, while appropriately developing nuclear energy;
- developing coal liquefaction technology and other oil substitutes such as methanol-alcohol;
- encouraging Chinese oil companies to develop oil supply sources outside the country;
- increasing energy conservation efforts;
- strengthening environmental protection; and
- increased international co-operation.

Energy market reform

China's energy industry has undergone major changes in recent years. In 1998, the government abolished the two remaining energy ministries – the Ministry of Power and the Ministry of Coal – and re-organised the state-owned oil and gas assets into three vertically integrated companies – the China National Petroleum Corporation (CNPC), the China Petrochemical Corporation (SINOPEC) and the China National Offshore Oil Corporation (CNOOC). All three oil and gas companies have established private branches, which have been listed in international stock markets.

Short of a single central administration in charge of energy matters, the government's energy responsibilities are shared mainly between the State Development Planning Commission (SDPC), the State Economic and Trade Commission (SETC) and the Ministry of Land and Natural Resources (MLNR).

Energy sector reform today concerns mainly the electricity and the oil and gas industries. It consists of improving the efficiency and the quality of service by introducing competition. It also consists of establishing an appropriate regulatory regime for each of these industries that would suit its development, given national circumstances. The government has announced plans to divide up the State Power Corporation of China (SPCC) to form several power generating groups that would compete with each other (see Box 4.3). It will, however, take time to implement the intended reform of the power sector. For the oil and gas sector, a new regulatory regime is also under elaboration, with the assistance of the World Bank.

New energy policy orientations

In the 10th Five-year Plans (FYP), which were elaborated in 2001 for the energy sector as a whole (Box 1.3), as well as for energy industries such as oil & gas, coal, electricity and petrochemicals, the government has set the priorities for energy work in the country. They include energy security and the building of strategic oil reserves, and energy structure rationalisation to increase the share of natural gas and other clean energy sources. Energy market reforms, including the introduction of competition in the electricity markets and the creation of regulatory systems for the oil and gas sectors, are also priorities for the next five years.

Box 1.3

China's Five-Year Plans

Since the first Five-year Plan (FYP) in 1953[7], China has maintained a tradition of preparing five-year plans to guide national economic and social development. However, the nature of these plans has changed significantly over the years from the days of strict central planning. At that time, the plans established command and control numerical targets for most economic sectors. Today, they serve only as a macro-economic guidance for ministries and government agencies.

The first step in the process is the setting of broad policy lines by the National People's Congress (NPC), the country's Parliament. Next, the State Development Planning Commission (SDPC) prepares national-level plans in a number of key areas. The areas selected for making specific national plans are those considered critical or weak, where the government is concerned that market forces alone will not suffice. The procedure further requires that all government departments and all regions make their industry-specific or region-specific plans, guided by the NPC's outline and the SDPC's sector-specific plans.

The energy plans for the 2001-2005 period were prepared in the following sequence. In March 2001, the National People's Congress passed the "Outline of the 10th FYP for National Social and Economic Development", which has one section on energy. In May 2001, the SDPC produced a more elaborated document on the "Outline for Energy Sector Development

7 The People's Republic of China started the Five-year Planning exercise in 1953, with the first FYP covering the period of 1953-57 and the second one 1958-62. In 1963, an adjustment was made to cover only 3 years (63-65) so that subsequent plans cover either first or second half of a decade, e.g. 66-70 and 95-2000.

within the 10th Five-Year Plan". This time, energy was selected by the SDPC as one of the 13 sectors or areas[8] that need specific national plans. In June, the State Economic and Trade Commission (SETC), which is responsible for formulating and implementing sectoral programmes and for regulating business activities, also published 13 industry-specific FYPs, which include plans for oil (including natural gas), coal, electricity, and petrochemicals[9]. These industry-specific plans, together with the SDPC's energy plan, demonstrate the Chinese government's effort to put in place an integrated energy policy.

Under the general objective of "...meeting the energy needs of national economic and social development", the main objectives for the energy sector during the 10th FYP period are:

- to achieve substantive progress in the rationalisation of the energy supply structure;
- to further improve energy efficiency;
- to build a modern energy management system that is compatible with the country's socialist market system;
- to build competitive systems in energy infrastructure design, equipment manufacturing, energy transportation and operation; and
- to achieve visible progress in developing the western and middle regions of the country.

Key energy policy orientations

The FYPs proposed the following new orientations for energy-sector development within the next five years. According to the Plans, China's first priority in energy is to rationalise the energy supply structure, while improving the country's energy security. This means increasing the share of clean and more efficient energy sources including natural gas, hydropower and other clean fuels and reducing the share of coal in selected end-uses. Another over-riding priority is to accelerate the development of western China, which is part of the "Developing the West" campaign. Ensuring energy supply security is a precondition for implementing the overall energy strategy. For that, the Plans recognise the need for the country to rely on domestic sources of energy, especially coal, for the foreseeable future. Other energy security measures called for in the FYPs include the increased links with international energy markets, the establishment of strategic oil reserves, the diversification of energy imports, the development of alternative fuels to oil, and the more aggressive adoption of energy-saving technologies.

The FYPs also set the following policy orientations for individual energy industries:

Oil:

- The most notable policy initiative is the call for the establishment of national strategic oil reserves. The objective is twofold: to ensure the security of the oil supply; and to enhance

8 Those 13 sectors or areas include: urbanisation, population, employment and social security, science technology and education, ecological construction and environmental protection, water resources development, comprehensive transportation systems, energy development, WTO and international competitiveness, information technology development, and western region development.

9 Other industries include the mechanical industry, automobile, iron and steel, precious metals, chemicals, pharmaceuticals, construction materials, light industry and the textile industry.

the government's ability to stabilise internal markets. The target for the five years is to have "a limited level of national strategic oil reserves" in addition to commercial stocks held by oil companies.

- Another important policy orientation is the expansion of international co-operation. This policy has two prongs: one is to attract more foreign capital and technology to exploration activity in China; the second is to encourage Chinese companies to invest internationally in oil and gas.

Gas:

- The desirability of expanding natural gas use is clearly laid out in the FYPs. The plans call for the strengthening of domestic and international exploration and the development of natural gas in addition to the traditional emphasis on oil. They also call for the acceleration of work on gas pipelines and downstream networks and gas end-users. This illustrates the government's determination to increase the share of natural gas in the country's energy structure. However, natural gas only occupies a few paragraphs in the FYPs and there is no detailed statement on how to meet the target.
- The "West-East" gas transportation pipeline and the Guangdong LNG import terminal are both high priorities highlighted by the FYPs.

Coal:

- Coal strategy has four volets: consolidating small interests into larger commercial coal groups; accelerating technology deployment; developing clean coal technologies; and creating vertically integrated business chains.
- The policy of closing down unsafe and inefficient small coal mines will continue. A new emphasis will be put on coal exports.

Electricity:

- The emphasis here is on national grid construction and interconnection. The rationalisation of thermal generating units (i.e., shutting down small and inefficient units) receives special attention. Another emphasis is the construction of the "West-East" power transmission lines to transport electricity from large-scale hydro and coal-mine-mouth stations in the west to eastern markets.
- On regulatory issues, the objective is to break down or manage monopoly power and to introduce real competition. Generation will be separated from transmission and competition between generators will be promoted. The revision of the 1996 Electricity Law[10] and other regulations is also proposed.

10 The 1996 Electricity Law was elaborated at the time when there was electricity shortage and the electricity sector was still managed by the Ministry of Power. While it still provides the legal basis for the electricity sector's operations, it is no longer considered adequate for the changed situation where the need for competition in power generation is a key issue.

Nuclear, hydro and renewables:

- The plans call for "an appropriate development" of nuclear power and for development of domestic capability in manufacturing nuclear power equipment.
- Hydropower is encouraged. The plans call for the development of large-scale hydro projects in areas where hydro resources are abundant and grid connections are adequate.
- The plans also call for the development of renewable energy as part of a longer-term sustainable development strategy. In areas where resources are abundant and grid connections exist, large scale wind farms, solar heat and power are encouraged.

Energy efficiency:

- The emphasis is on the implementation of the 1997 "Energy Conservation Law", with special attention to energy intensive industries.
- Saving oil is also considered a strategic task, in line with the government's objective of oil security.

Main numerical targets for 2005

The FYPs also set the following indicative numerical targets for the energy sector in 2005:

- Total primary energy to reach 1,320 million tonnes of coal equivalent, 21% above the 2000 level;
- Coal production to reach 1,170 million tonnes, up 17% from the 2000 level of 998 mt;
- Oil production to maintain the 2000 level of 165 million tonnes;
- Natural gas to reach 50 billion cubic metres, 85% above the 2000 level of 27 bcm;
- Hydropower production to reach 355.8 TWh, 48% above the 2000 level of 240 TWh;
- Nuclear power to reach 60 TWh, up 266% from the 2000 level of 16.4 TWh.
- Total installed power generating capacity to reach 370 GW and annual power generation at 1,730 TWh, representing respectively annual growth rates of 3.2% and 5.1%;
- Reduce the share of coal in primary energy consumption by 3.9 percentage points and increase the share of natural gas, hydropower and other clean energy sources by 5.6 percentage points;
- Increase the coal washing rate from the current 30% to 50%;
- Increase the share of hydro, gas, nuclear and other clean fuels in the total power generation mix from the current 26% to 31%; close down a total of 14.2 GW generating capacity from small units and increase the share of large generating units (>300MW) from the current level of 38% to 50%; and increase thermal conversion efficiency by 3.5 percentage points;
- Reduce the energy intensity of GDP by 15-17%, which represents the saving of 300-340 million tonnes of coal equivalent, or 150 million tonnes of carbon.

THE ENVIRONMENTAL CONTEXT

As the result of the past few decades of environmental negligence, China today faces grave environmental problems, including serious air pollution, water contamination and land degradation.

China is the world's largest water polluter. According to China's State Environmental Protection Administration (SEPA), all seven of the country's extensive river systems and several major lakes are contaminated with sewage and toxic chemicals, and land degradation is stripping two million hectares of grassland every year.

Air pollution is perhaps the most visible and serious environmental problem facing China today. In 1998, the country discharged 21 million tons of sulphur dioxide (SO_2), 14 million tons of soot and 13 million tons of total suspended particulates (TSP), all ranking the first in the world. While in the past, sources of air pollution were largely stationary, the explosive growth of motor vehicles represents a new and mobile source of pollution that is difficult to control. According to a recent World Bank study[11], TSP is China's most significant air pollutant, followed by SO_2. Pollution by nitrogen oxides (NOx), which is a main cause of smog, is also increasing. In 1999, only one third of China's 338 monitored cities (China has a total of 667 classified cities) were in compliance with the country's residential ambient air quality standards. 80% of China's population still use solid fuels such as coal, firewood, and crop stalks for cooking and space heating, which lead to serious indoor air pollution.

Serious air pollution has also resulted in the following situation:

- 40% of China's land has the pH value of its rain below 5.6 – the international definition of acid rain. Acid rain also affects neighbouring countries.
- According to a 1998 report of the World Health Organisation, seven of the ten most air-polluted cities in the world are in China (Taiyuan, Beijing, Urumqi, Lanzhou, Congqing, Jinan and Shijiazhuang), with the other three being Milan, Mexico City, and Teheran.
- The cost of air and water pollution, in terms of damage to people's health and to the economy, is in tens of billions of dollars, which represents several percentage points of the country's GDP[12].
- Hundreds of thousands of people die prematurely because of excessive air and water pollution.

The coal-dominated energy structure takes a large part of the blame. Coal-burning is estimated to be responsible for 85% of SO_2, 70% of soot and TSP, 85% of CO_2 and 60% of NOx that are released into the atmosphere across the country. Nearly half of coal is burnt directly with minimal or no emission controls by hundreds of thousands of small boilers. Moreover, as coal is the main fuel for heating in urban areas, air pollution tends to be more serious in cities in northern China where it is cold in winter. For the same reason, air pollution is more severe in winter and spring than in summer and autumn.

The government has taken a number of initiatives to address energy-related environmental problems. For example, to address the acid rain problem, in 1998 the government mapped out an "Acid Rain Control Area" and a "SO_2 Control Area" and started to implement strict control on energy activities in these two areas (see Annex 1). A number of cities, including Shanghai

11 World Bank, 2001, *China: Air, Land and Water – environmental priorities for a new millennium*. Washington DC.

12 According to a World Bank study, air and water pollution cost China US$24 billion in 1995, accounting for 3.5% of the GDP in that year.

and Beijing, banned the use of coal within the cities and ordered the compulsory conversion of coal-fired boilers into oil or gas. In the 10th Five-Year Plan for Social and Economic Development and the 10th FYP for environmental protection, the government has set an ambitious target of reducing the total emission of pollutants by 10% below the 2000 level no later than 2005. In 2002, the government announced that it would spend US$85 billion in an environmental clean-up campaign over the next ten years.

Annex 1 of this report summarises a number of environmental protection laws and regulations that China has put in place so far. As noted in the above-cited World Bank report, China's repertoire of environmental laws, regulations and standards is quite comprehensive and has been continuously updated and expanded to improve effectiveness and cover emerging issues. But its performance is far behind the best OECD countries. The World Bank report noted three important challenges for environmental management in China over the next decade:

- First, the environmental agenda is becoming so complex and large that it cannot be adequately managed by one agency – the State General Administration for Environmental Protection (SEPA) and its counterparts at lower level – working on its own. Effective solutions will require the combined and co-ordinated efforts of many different branches of government and the re-thinking of many development policies.
- Second, the systemic fiscal and budgetary problems facing the country as a whole are making it difficult for environmental institutions to do their work. There is a growing gap between the assigned responsibilities and the resources provided to carry out those responsibilities.
- Third, the government has to continue to diversify the approaches it takes and the environmental tools it uses to provide a better fit between the solutions developed and the problems being experienced in different parts of the country. The "one-size-fits-all" approach is proving increasingly inadequate to solve current problems.

The World Bank study has also provided a number of recommendations on China's environmental management (Box 1.4).

Box 1.4

World Bank Recommendations on Actions to Meeting China's Environmental Challenges

In the areas of institutional arrangements for dealing with environmental issues:

- Mainstreaming environmentally sustainable development into policies and programmes of all governmental agencies;
- Cross-sectoral co-ordination between agencies to reduce overlaps and contradictions and to maximise synergies;
- Reform the approach to biodiversity conservation;
- Push forward with integrated river basin management in water-scarce regions;

- Increase environmental protection bureaus' (EPB) capacities and effectiveness, with particular emphasis at the local level;
- Strengthen the legal system; and
- Continue to promote public participation in environmental decision-making.

In the area of the instruments applied to achieve environmental objectives:

- Adopt a new approach for point-source pollution control;
- Keep working on supplementary control strategies;
- Continue price reform for environmental improvement;
- Strengthen the focus on the poverty/land degradation connection; and
- Re-orient natural resources development policies.

In the area of investments made to underwrite environmental programmes:

- Keep focused on priority issues;
- Increase environmental expenditures in real terms;
- Improve the effectiveness of investment in ecological construction and conservation;
- Invest more and smarter in urban environmental infrastructure; and
- Make less haste and give more thought to environmental improvement programmes.

Sources: World Bank, 2001, *China: Air, Land and Water – environmental priorities for a new millennium*. Washington DC. pp. xviii-xxiii.

CONCLUSIONS

This chapter describes the economic, energy and environmental context of China today. It can be seen that the context is very favourable for the growth of China's natural gas industry. A "small-rich" society is no longer happy with the quantitative and low quality supply of energy. It demands clean and high quality fuels. The government's priority task in rationalising the energy supply structure by increasing the share of clean energy sources, coupled with the country's need for energy security, provide important opportunities for the growth of natural gas use. Natural gas also has an important role to play in meeting China's urgent need to reduce serious environmental pollution, especially air pollution, that inflicts the country as a whole.

CHINA'S NATURAL GAS MARKET: TODAY AND TOMORROW

Highlights:

- *China has set very ambitious gas development targets: doubling gas production between 2001 and 2005, more than doubling the share of gas in the country's primary energy supply within ten years and building a well interconnected national gas transmission system within a slightly longer time horizon.*
- *Reaching these targets depends not only on the technical and financial ability of the country's gas industry to build the infrastructure, but more critically on its capacity to successfully develop the downstream gas market. A number of energy policy challenges confront both the government and industry.*

CHINA'S NATURAL GAS MARKET TODAY

China was one of the first countries in the world to utilise natural gas some 2000 years ago when gas was produced and transported in bamboo pipes. However, despite this promising start, the natural gas industry did not experience the recent rapid development that occurred in the rest of the world.

Table 2.1

Evolution of Chinese Gas Demand and its Share in Total Energy Consumption

	1965	1970	1975	1980	1985	1990	1995	2000
Gas consumption bcm/y	0.9	3.7	9.7	13	12.8	14.7	16.6	25
Gas as a % of total energy consumption	0.4	1.4	2.6	2.8	2.1	2	1.9	2.5

In 2000, China produced 27.2 bcm of natural gas, ranking it 15th in the world. Part of the gas produced is exported to Hong Kong, China. Natural gas only represents about 3% of the country's total primary energy supply (TPES) and about 2.5% of the total energy consumption. This is very low compared to the world average of 24% and to the Asian average of 8.8% of gas in the TPES.

But the Chinese Government is planning a dramatic increase of gas in the country's energy supply mix over the next ten years, with the target of 6% of TPES by 2010. Increasing the share of natural gas is at the heart of the SDPC's proposed top priorities in rationalising the energy supply structure.

Gas production

By region/basin

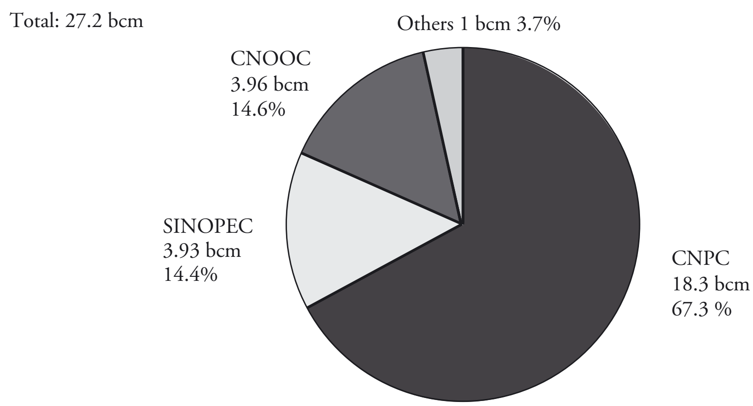
The major part of China's current natural gas production comes from the following locations (Map 2):

- *Sichuan province* in the south-west, which produces about one third of China's total. Until now, gas has only been consumed within the province, mainly for fertilizer production, and transported by an annular pipeline linking principal cities of the province and the city of Chongqing. A new pipeline is under construction to transport gas to Wuhan, the capital city of the neighbouring Hubei province, with a future extension to Shanghai.
- *Daqing and Liaohe oil fields* in the north-east: these are two of the largest oil fields in China. Their associated gas accounted for 17% of the country's total gas production in 2000.
- *The Ordos/Shaanganning basin* in north China, mainly the Changqing field, which accounts for around 10% of the national total. The gas is piped to Beijing (through an 865km pipeline), and to Xi'an and Yinchuan.
- *Tarim basin in Xingjiang and Qaidam basin in Qinghai*: both are in the far north-west part of the country. Their production is still limited due to the lack of an outlet infrastructure. One pipeline of 953 km was just completed in November 2001 to link Qaidam basin to Lanzhou city, and another pipeline, the famous West-East Gas Pipeline, is under construction to link the Tarim basin to Shanghai on the east coast.
- *Offshore areas* including:
  - East China Sea basin: only from the Pinghu field, which started to supply Shanghai in 1999 through an offshore pipeline (375 km). New gas fields in Xinhu Fossa are being developed and other pipelines are planned.
  - Yinggehai basin in the South China Sea: mainly Yacheng-1 field, which supplies Hong-Kong through a 778 km pipeline and Sayan in the southern part of Hainan island *via* a much shorter pipeline.
  - Bohai gulf: two fields are currently producing gas, supplying Jinzhou and Tianjin.

By producers

Figure 2.1

Gas Production by Producers in 2000



Source: ERI/SDPC.

Of the total output in 2000, CNPC/PetroChina accounted for 67.3%, followed by CNOOC at 14.6%, and SINOPEC at 14.4% (Figure 2.1). This underscores the importance of PetroChina in the country's upstream gas activities. 70% of the total gas produced is non-associated gas, while the remaining 30% is associated gas produced in oil fields.

Gas infrastructure

China today has around 20,000 km of high-pressure natural gas transportation pipelines and 34,000 km of gas distribution pipelines. Map 3 of the present report shows the existing gas infrastructure, including pipelines and LNG receiving terminals that have already been built or are under construction in China.

Most existing pipelines were built to connect a single gas field to a single user, which is very often a fertilizer plant. They were mainly built in the 1960s and 1970s without gas storage facilities. The technologies used for building those pipelines are now well outdated, management is poor, and supply reliability desperately low. Most have never reached the designed transmission capacity – the average capacity utilisation rate is below 50%.

Recognising that the lack of gas transportation infrastructure is the key obstacle to gas market development in the country[1], China has stepped up efforts in pipeline construction in recent years. Table 2.2 provides a summary of the pipelines that have been built since 1996.

Table 2.2

Gas Pipelines Built in Recent Years in China

Route	Diameter (mm)	Time of commercial operation	Length (km)
Ya-13-1 – Hong Kong	711	1996	778
Shanshan-Urumqi	457	1996	302
Tazhong-Lunnan	426	1996	315
Sebei-Golmud	–	1996	189
Jingbian-Beijing	660	1997	853
Jingbian-Xian	426	1997	488
Jingbian-Yinchuan	426	1997	320
Lunnan—Kuerle	610	1998	193
Pinghu-Shanghai	355	1999	375
Sebei—Xijing—Lanzhou	660	2001	953
Zhongxian – Wuhan	711	2002-03 (expected)	695

Source: PetroChina, SDPC, and Quan & Paik (1998).

In addition to those listed in the table, a number of small-scale natural gas pipelines have been built. They include pipelines from the west Bohai oil field to Tianjin, from the Dongfang gas

1 Lack of transportation infrastructure is reportedly responsible for the flaring of 8-10% of China's gas production.

field in the South China Sea to Hainan island, from Sebei to Golmud in Qinghai province and from Baxian in Qinghai province to Dunhuang in Gansu province.

China's most significant gas infrastructure is the famous West-East Pipeline (WEP) for gas transmission. By 2005, the 4,000 km pipeline will link Xinjiang's Tarim basin in the far west to Shanghai, in the east, and will bring 12 bcm/y of gas to consumer regions in east China (see more details in Chapter 7). According to CNPC, China will build 12,000 km of new pipelines during the 2001-2005 period, 9,000 km from 2006-2010, and 11,000 km from 2010-2015.

One LNG receiving and regasification terminal is also under construction in Guangdong province with an initial import capacity of 3 million tonnes per year (mt/y). The terminal is scheduled for first commercial operation by 2005. Another LNG terminal in Fujian province is also firmly planned (see more details in Chapter 8).

Gas consumption

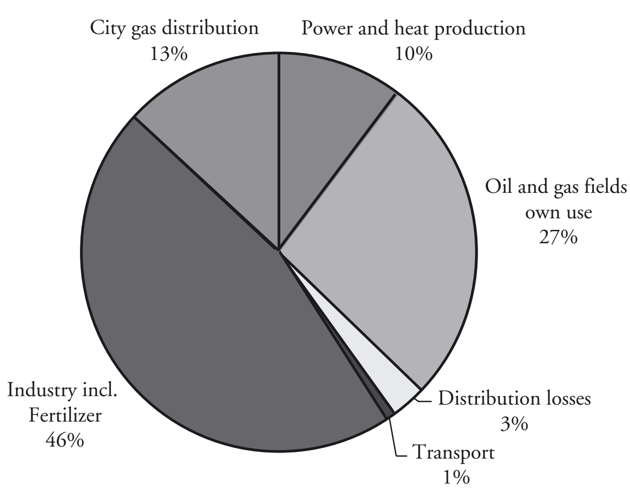
By geographical areas

Currently, gas is mainly consumed where it is produced, except for the Ordos basin and the South China Sea basin where pipelines have been built to transport gas over a relatively long distance. Sichuan province is the largest consumer area, with a relatively well-developed local pipeline network. The second largest gas consumer area is north-east China, where oil fields produce high quality associated gas.

By sector

Figure 2.2

Natural Gas Consumption by Sector in 1999



Source: IEA.

In 1999, China (excluding Hong Kong where gas is also supplied by CNOOC from its South China Sea production) consumed 24 bcm of natural gas. The chemical sector, mostly fertilizer production, accounted for 39% of the total, followed by oil and gas fields' own uses (27%), city gas distribution (13%) and power and heat production (10%) (Figure 2.2). No reliable data is available on the share of power generation in total gas consumption. Most gas-fired plants are situated within the oil and gas fields so they are accounted in the oil and gas fields' own gas uses. In 2001, gas sold to power plants accounted only for 0.9% of PetroChina's total gas sales of 15 bcm.

Hence, the fertilizer industry is the largest consumer of natural gas. Both power generation and residential uses are still very limited.

NATURAL GAS DEMAND OUTLOOK

The future demand for natural gas in China will be mainly driven by two factors:

- the need for new sources of energy to fuel economic growth and improve living conditions;
- the desire to reduce the consumption of coal and thus the level of pollution.

The balance between these two driving forces varies across China: the north of China has vast reserves of coal but faces very serious atmospheric pollution. The booming coastal provinces in south and east China require additional supplies of energy, preferably in its clean forms. These drivers are, however, subject to a number of constraints in determining the actual level of gas demand: the price of gas and its competitiveness *vis-à-vis* other fuels and the rate at which the downstream market is developed in both power and non-power sectors.

Demand projection by various sources

There are many different projections on China's future natural gas demand for the period up to 2020 (Table 2.3).

Table 2.3

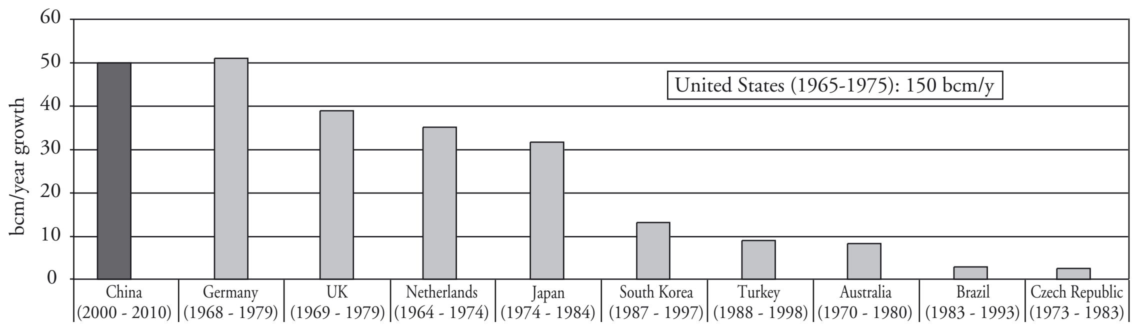
Projections of Natural Gas Demand in China

Source	2000		2005		2010		2015		2020	
	Volume bcm/y	% of TPES	Volume bcm/y	% of TPES	Volume bcm/y	% of TPES	Volume bcm/y	% of TPES	Volume bcm/y	% of TPES
PetroChina		2.5	63.7	4.8	106.8	7.4	153.4	9.4	210.7	12
ERI/SDPC	25.7		64.5		120	7	160		200	12
BP	25	2.6	42	3.8	74	6.4	135	9.8	177	11.6
CNOOC			61	4.6	100	5.6	150	8.2	200	9.8
EIA/DOE			51		79		127		181	

Sources:
PetroChina: Liu Hequn, 2001, *"Chinese Gas Market Prospects"*, Market Research Department, Planning & Engineering Institute, PetroChina. Presentation at the IEA-China Seminar on Natural Gas, Beijing, 15 November.
ERI/SDPC: Liu Xiaoli, 2001, *"A Prospect of Gas Supply & Demand in China"*, Energy Research Institute of the SDPC. Presentation to the IEA Gas Experts Mission, Beijing, 13 November.
BP: *Presentation to the IEA Gas Experts Mission*, Beijing, 12 November. BP has three scenarios: P10, P50 and P90. The numbers included here correspond to those of scenario P50.
CNOOC: Zhu Wenda, 2002, *"Development Plan and Market Prospects for China's Coastal Gas"*, ABF China Gas Conference, 9 May 2002.
EIA/DOE: US DOE Energy Information Administration, *International Energy Outlook*, 2002. Reference case.

Figure 2.3

China's Gas Growth Target Compared with Experiences of Other Countries (bcm/y within the indicated period)



Source: BP, IEA.

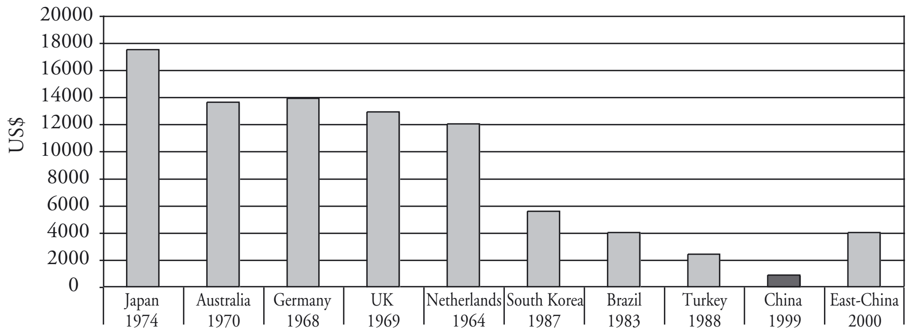
Most projections show that between 2000 and 2020, natural gas demand could be multiplied by eight, from about 25 bcm/year to 200 bcm/year, representing an annual growth rate of more than 10%. Natural gas will also increase its share in the energy mix, from around 2.5% in 2000 to 12% in 2020. The annual growth in volume will be unprecedented in China and rare in the world. Even with the least optimistic projection, the volume growth is expected to be 50 bcm/y within a decade. Except for the United States, which experienced very rapid gas market development in the 1960s-70s, only Germany had a similar level of growth during the 1968-1979 period, when its gas supply volume increased by 50 bcm within eleven years (Figure 2.3).

Many of the demand projections cited above concern an assessment of demand potential, as the assumptions – in particular the price assumption – behind these figures are far from clear. If they do not take into account the price factor, they may appear to be too optimistic. In its 2002 edition of the *World Energy Outlook*, the IEA took a rather conservative position and projected China's natural gas demand at 61 bcm for 2010 and 109 bcm for 2020, representing respectively 4.4% and 6% of the TPES. These projections are only half of some of the more optimistic projections quoted above. It should be pointed out that the IEA projection is based on a "business-as-usual" scenario that does not take into account the future implementation of a strong "pro-gas" policy in China, while other projections may have included strong policy drivers for gas market development. Many uncertainties will affect the future gas demand level, particularly with respect to the cost of supply and China's ability to create an integrated national transportation and distribution network. Gas' competitiveness against coal in power generation will also be a key determinant of gas-demand growth. Even at these low projected numbers, gas demand is expected to grow at more than 7% a year, the fastest among fossil fuels.

Gas demand outlook by region

Figure 2.4

GDP/Capita Comparison of China and Other Countries at the Emergence of the Gas Market

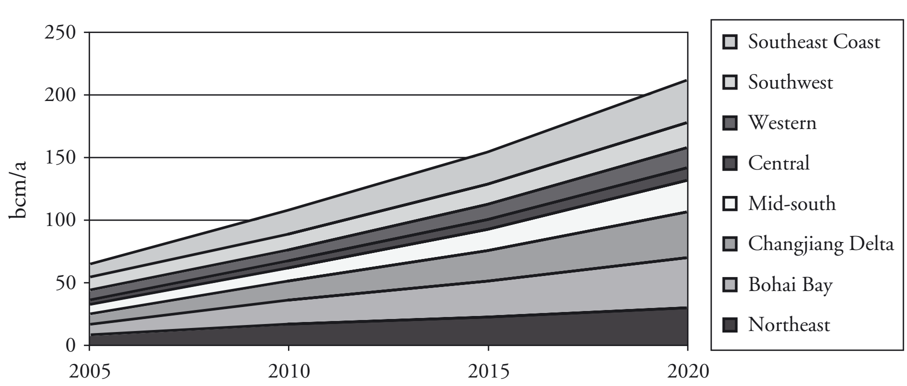


Source: BP, IEA.

China's current per capita GDP, at about US$850, is much lower than that of most countries when their gas markets began. This aggregate number masks, however, the considerable regional disparities described in Chapter 1. In fact, the per capita GDP is $4,000 in some cities and provinces on the east coast, putting them more on par with the level of Korea, Brazil and Turkey when those countries began their gas markets (Figure 2.4). Consequently, demand centres for gas are mainly located in provinces and cities along the east coast. This does not, however, rule out the possibility for other poorer regions to successfully develop their gas markets if they have assembled the right conditions.

Figure 2.5

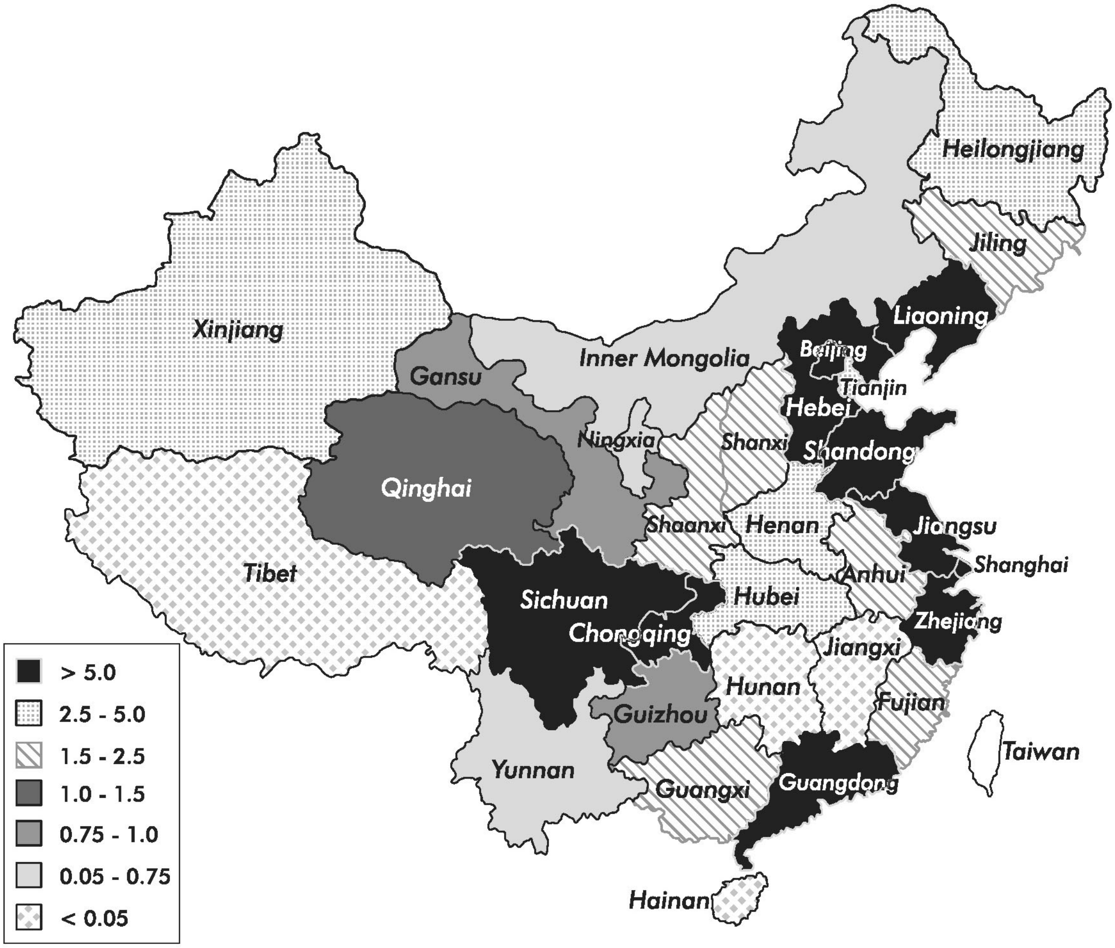
Projected Natural Gas Demand by Region



Source: PetroChina.

Figure 2.6

Possible Geographical Distribution of Future Gas Demand in China (total demand in 2010: 100 bcm)



Source: Gaz de France.

China's east coast includes the north-east, Bohai Bay, Yangtse Delta and the south-east coast. These areas are characterised by high energy demand growth, both in power and residential uses, and high levels of air pollution caused by coal burning, and where restrictions on coal uses have either already been or will be introduced. The Yangtse Delta (comprising Shanghai, Jiangsu and Zhejiang provinces) and the south-east coast also have increasingly limited access to domestic coal supplies or coal prices approaching international levels. In total, they will account for two-thirds of the country's total projected gas demand in 2010 and 2020. Figure 2.6 provides a projection of gas demand distribution among the Chinese provinces in 2010.

Among the growing areas, Guangdong, Fujian, Zhejiang, Shanghai and Jiangsu provinces (GFZSJ) merit special consideration, as they are the most vibrant provincial economies and hence the most important potential gas consumers. The GFZSJ's GDP growth ranged from

13-19% in the first half of the 1990s and was around 10-12% in the second, much higher than the national rate. Although future growth is likely to be slower than in the past, these provinces will still remain the most dynamic in China. Consequently, their energy demand growth is likely to be much higher than the national average (Table 2.4).

Table 2.4

Projected Energy Demand in China's Coastal Provinces (Million tons of coal equivalent, or mtce)

Province/City	1995	2000	2010	2020	Annual growth rate 2000-2020
Shanghai	45	59	89	117	3.5%
Jiangsu	80	105	166	236	4.1%
Zhejiang	46	68	106	145	3.8%
Fujian	21	35	62	91	4.9%
Guangdong	61	85	148	209	4.6%
Total GFZSJ	253	322	571	798	4.6%
% of country	19.3%	21.3%	27.4%	30.2%	
National Total	1,312	1,515	2,083	2,640	2.8%

Source: World Bank (2000), *Liquefied Natural Gas in China: Options for Markets, Institutions and Finance* (Discussion Paper number 414).

From an energy supply point of view, these coastal areas are encountering the following problems:

- Local resources are either not available at all or very limited. This requires the coastal provinces either to buy domestic coal brought by train or barge involving several thousand kilometres of transportation; or to build nuclear power stations.
- Bulk transportation of coal from mines in the northern part of the country is increasingly limited by rail and shipping availability. The high transportation cost makes domestic coal prices equivalent to international prices in Shanghai ($40/ton for high quality coal, or $34/ton for lower quality).
- Limitation in the high-voltage power transmission system to carry electricity from central and western part of the country, which makes coal-by-wire difficult. Current government plans focus on the construction of a national power transmission system, and there is a programme of west-east power transmission (see Chapter 1).
- Serious environmental pollution caused by coal burning, especially lower quality coal with high sulfur content. The government has included major cities in all these provinces in the acid rain control zone.

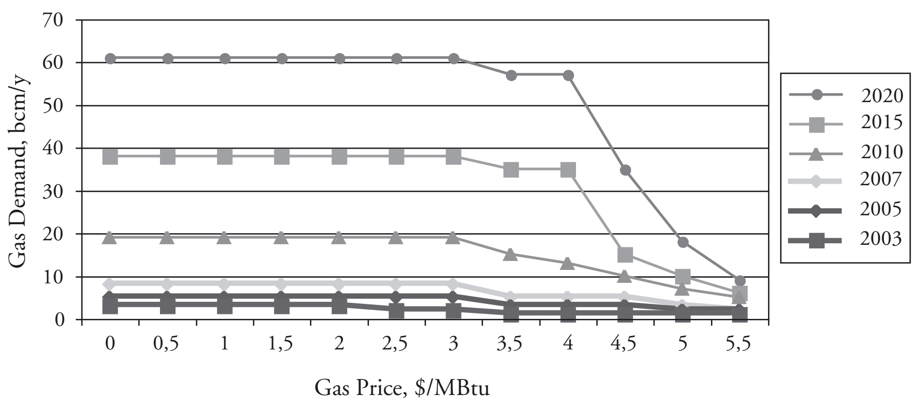
Using a cleaner source of energy, such as natural gas, would appear to be a good solution to many of the problems described above. There are four natural gas sources available for the GFZSJ coastal markets:

- Chinese offshore gas landing supplies (East China Sea, South China Sea and Bohai Gulf);
- Domestic inland gas supplies from central and western part of the country;
- Pipelined gas imports from Russia; and
- LNG imports.

Currently, only Shanghai is supplied with natural gas (0.22 bcm in 2000) from the Pinghu field in the East China Sea. Future demand growth will depend critically on the competitiveness of gas prices and on the marketing efforts of gas distribution companies. The above-quoted World Bank study made an explicit link between the price of gas and the potential demand in the Yangtse Delta region as shown in Figure 2.7.

Figure 2.7

Projected Demand for Gas in the Yangtse Delta Region



Source: World Bank, 2000.

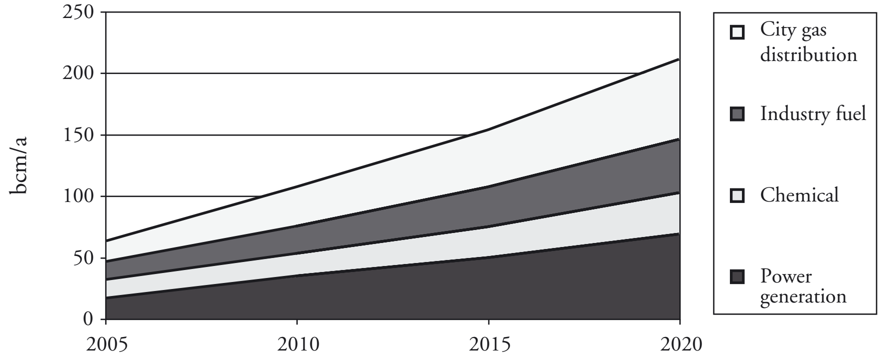
The merit of this demand projection lies in the fact that it links the volume of gas demand to the price of marketed gas. It shows that at US$3/MBTU (RMB0.9/cm) or below, gas demand build-up in the Yangtse Delta Region is relatively straightforward. Above $4/MBTU however, demand growth will be difficult. Assuming a gas price in the range of US$4-4.3/MBTU (approximately RMB1.2-1.3/cubic meter), the World Bank study forecast that gas demand in the Yangtse Delta Region would be 2.5 bcm in 2005, 12-14 bcm in 2010 and 35-55 bcm in 2020.

Gas demand projection by sector

Figure 2.8 provides one projected evolution of China's natural gas demand by sector. According to this, power generation and urban gas distribution are the two main areas of growth. They will each account for about one third of total gas demand in 2010 and 2020.

Figure 2.8

Projected Natural Gas Demand by Sector



Source: PetroChina.

Table 2.5 provides another projection carried out by SDPC's Energy Research Institute and Australia's Murdoch University. It also shows that power generation and residential use will be the two major sectors for future growth in gas demand.

Table 2.5

Actual and Forecast Demand for Natural Gas in China (bcm/y)

	1997 Actual	2010	2020
Power Generation	2.19*	35	81.2
Residential Use	2.12	22	50
Chemical/Fertilizer	8.43	19	32.5
Industry and Others	6.82	20	40
National Total	19.56	96	203.7

* including gas use in Hong Kong. Excluding Hong Kong, the volume would only be 0.6 bcm.
Source: Murdoch University, 2001. *China: Energy Policy and Natural Gas Use.* Asia Research Centre, Perth, Western Australia. p.23.

Obviously, these forecasts of gas demand are subject to a high degree of uncertainty, because gas consumption depends to a considerable extent on the construction of infrastructure, price competitiveness, rate of gas penetration in power and non-power sectors, especially the rate of conversion of existing manufactured gas distribution and consumption facilities.

Gas reserves

Assessing proven gas reserves in China remains a challenge, as different sources give different numbers. Even within the CNPC, which was the sole onshore upstream operator until 1998, the number varies according to experts. Furthermore, there exist significant differences in terminology used in China and elsewhere. Indeed, unlike their Western colleagues who attach great importance to the notion of "proven reserves[2]" that are commercially recoverable under current conditions, Chinese geologists often talk about gas resources that do not have any operational value. Box 2.1 provides an explanation of various notions of oil and gas reserves used by Chinese geologists.

Box 2.1

What Do They Mean? – Chinese notions of oil and gas reserves

Chinese geologists use the following terms to assess oil and gas reserves:

- *Resources (Ziyuanliang):* This refers to the total hydrocarbon resources underground that have been assessed based on a number of geological methods including chemical composition data, simulation and comparison with known fields. The majority of these resources may never be recovered.
- *Recoverable effective resources (Kekaicai Youxiao Ziyuanliang):* This refers to the part of the resources that can be identified or proved in the next 20-30 years. It is in the order of 20% (for gas) or 12% (for oil) of the total underground resources.
- *Proven geological reserves (Tanming Dizhi Chuliang):* This refers to the reserves that have been identified and calculated after drilling and field appraisal. The amount needs to be approved by the National Reserves Committee. The proven geological reserves are divided into three classes according to the degree of uncertainty[3].
- *Recoverable reserves (Kekaicai Chuliang):* This refers to the part of proven geological reserves that can be recovered under present technological and economic conditions. It is in the order of 60-65% in the case of gas and 30% in the case of oil of the proven geological reserves.
- *Remaining recoverable reserves (Shenyu Kekaicai Chuliang):* This equals the difference between recoverable reserves and cumulative production. It is more or less equivalent to the western definition of proven reserves.

2 Proven or proved reserves are defined as "those geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions". Source: *BP Statistical Review of World Energy*: 1998.

3 Class I refers to those reserves that have already been recovered; Class II refers to the reserves that are to be recovered, with about 20% of error margin; and Class III refers to those reserves that still need further work to prove and the error margin is around 30%.

While the above notions define oil and gas reserves in descending order, Chinese geologists also use the following two other notions of reserves:

- *Controlled geological reserves (Kongzhi Dizhi Chuliang):* This refers to the reserves that have been appraised by the oil and gas companies but have not been approved by the National Reserves Committee.
- *Predicted geological reserves (Yuce Dizhi Chuliang):* This refers to the reserves that have been estimated based on seismic survey and geological analysis but have not been approved even by the companies. They only serve as a basis for further geological work.

Source: IEA.

In 1994, China conducted the second assessment of national oil and gas resources. Based on the assessment of 150 sedimentary gas bearing basins, it was concluded that geological resources of natural gas stand at 38 trillion cubic meters (tcm), 78.6% inshore and 21.4% offshore. Of this total, 10.5 tcm is believed to be ultimately recoverable.

Table 2.6

Geographical Distribution of Natural Gas Resources in China (bcm)

Gas Basin	Resources	Proven Reserves			Controlled Geological Reserves	Predicted Geological Reserves
		Geological Reserves	Recoverable Reserves	Remaining Recoverable Reserves		
Sichuan	7,185.1	578.7	399.5	217.9	123.8	207.0
Ordos/Shaanganing	4,179.7	341.5	186.6	184.4	156.7	426.8
Qaidam	1,050.0	147.2	80.0	79.2	36	138.3
Tarim	8,389.6	218.3	143.5	137.4	248.4	401.3
Yinggehai, South China Sea	2,239.0	250.3	182.4	169.1		
East China Sea	2,480.3	47.4	19.8	19.8		
Others	12,600.3	477.1	273.9	193.4		
National Total	38,124.0	2,060.5	1,285.7	1,001.2		

Source: SDPC.

Table 2.6 provides official Chinese data on gas resources and various notions of reserve. It should be noted that only the column of "Remaining Recoverable Reserves" corresponds to the western notion of proven reserves. Table 2.7 provides several recent estimations of China's proven natural gas reserves from international sources.

Table 2.7

China's Proven Natural Gas Reserves (tcm)

Source	Year of Estimation	Proven Natural Gas Reserves
Oil and Gas Journal	1/1/2000	1.367
BP	End 2000	1.37
Shell	End 2000	1.6
Cedigaz	1/1/2001	1.515

Distribution of gas reserves by region/basin

China's natural gas reserves are unevenly distributed. The densely populated and economically fast-growing east is relatively poor in gas reserves, whereas the vast and remote west and central areas, as well as the offshore areas, have more abundant reserves.

Chinese geologists generally divide China into four large gas-bearing areas for assessing natural gas resources. Three of them are located onshore: the western area (Tarim, Jungar, Turphan-Hami and Qaidam basins), the central area (Ordos and Sichuan basins) and the eastern area (Songliao and Bohai Bay basins). The Tarim, Suchuan and Ordos basins together account for 53% of the country's total proven gas reserves.

Map 2 of the present report shows the gas reserves and production of main basins as of 2000.

The CNPC group holds the majority of onshore reserves (87%) with SINOPEC taking the rest. CNOOC holds all the offshore gas reserves.

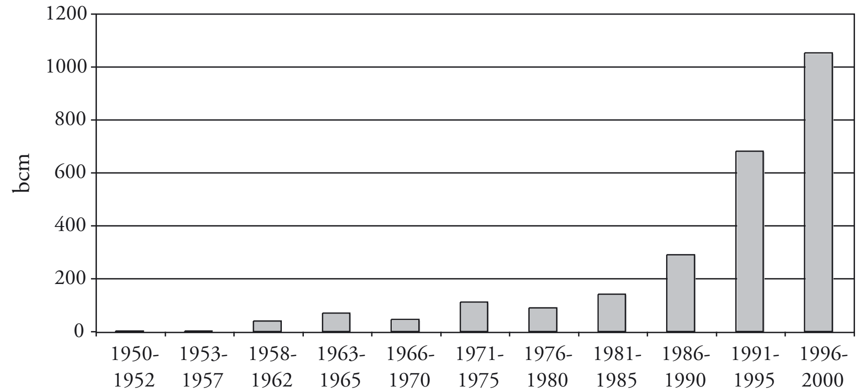
Growth of gas reserves

Over the past few years, China's proven gas reserves have been growing with the increased level of investment in exploration activities. According to the Energy Research Institute of the SDPC, China has proved an additional 1.05 tcm of natural gas reserves (identified geological reserves[4]) during the period 1996-2000 (Figure 2.9).

4 There is no clear definition of the nature of these additional proved gas reserves. They are likely to correspond to the Chinese notion of proven reserves as contained in Table 2.7, which actually correspond to the western notion of identified and probable reserves, that is, those reserves that have been identified but do not meet the criteria of "proven reserves" as defined earlier.

Figure 2.9

Increases in Identified Geological Gas Reserves in China



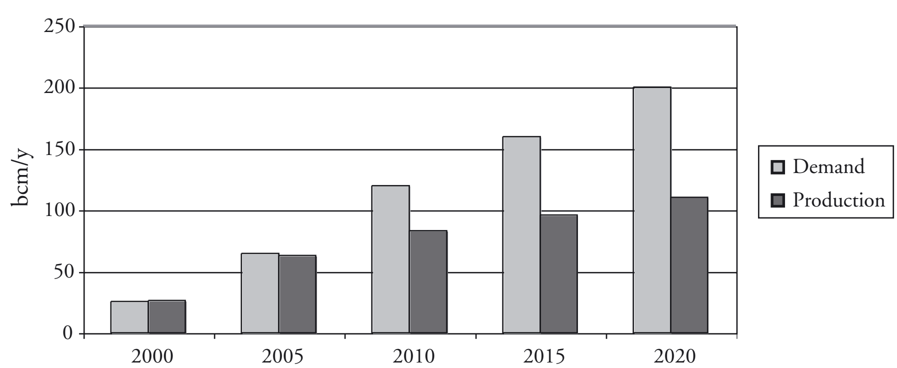
Source: Energy Research Institute, SDPC.

In addition to natural gas, China is also believed to have important volumes of coal-bed methane (CBM)[5]. This study does not discuss issues related to the development of CBM, although the development of a natural gas market will facilitate that of CBM.

Natural gas production forecast

Figure 2.10

Projection of China Natural Gas Demand and Production



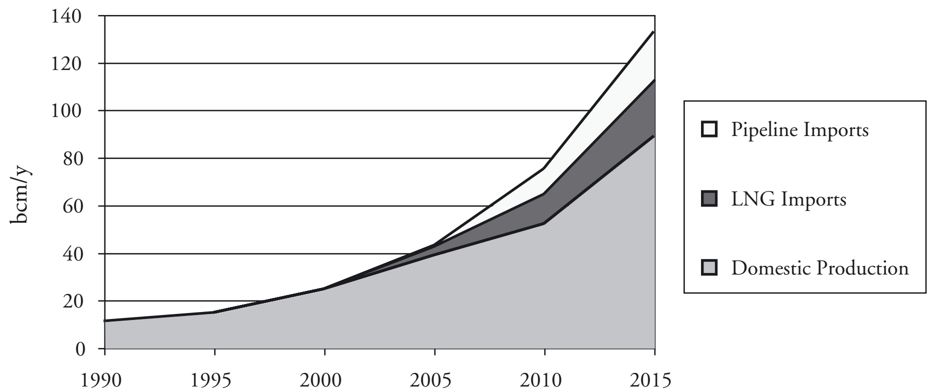
Source: Energy Research Institute, SDPC, 2001.

5 Unlike the inconvenient locations of natural gas resources, most of China's CBM resources are located in the middle and eastern regions of the country. The China United Coal-Bed Methane Corporation was established in 1996. Since then, it has signed several joint venture contracts with foreign companies (Texaco China BV, Greka Energy Corp., etc.). The company has a very ambitious target of producing 2 bcm of CBM by 2010 and 10 bcm by 2020.

China holds the potential to increase gas production in all major gas bearing basins, as suggested in Map 2 of the report. However, future gas production levels will rely very critically on the build-up of gas demand and on the construction of pipeline and distribution infrastructure. For 2005, the Government's 10th Five-year Plan (2001-2005) for the oil and gas sector calls for a doubling of natural gas production, from the current level of 27 bcm/y to 50 bcm/y, which represents more than 13% of annual growth. The Plan also calls for the construction of an additional 14,500 km of high-pressure gas transmission pipelines.

Figure 2.11

Projection of Natural Gas Supply in China



The SDPC's Energy Research Institute projects total domestic gas supply to be at 83 bcm/y in 2010 and 110 bcm/y in 2020 (Figure 2.10). According to this projection, between 2000 and 2020, the annual growth rate for natural gas demand will be 10.8%, while the annual growth rate for production is forecast to be only 7.5%. However, sources from international energy companies operating in China generally indicate a lower level of both demand potential and domestic production levels. Figure 2.11 provides a projection up to 2015 of China's natural gas supply by an international energy company. The differences are important in terms of import needs. The ERI/SDPC projection suggests a need for 64 bcm of gas imports by 2015, while that of the quoted international energy company suggests an import level of only 44 bcm by the same year.

Gas import options

All projections on China's natural gas supply and demand suggest a need for gas imports, either in the form of pipelined gas or as LNG. One source suggests that by 2020 China will need to import one third of its gas needs by pipeline (15% of the total) and LNG (18%). The actual volume from both sources will depend very much on the progress of long-distance gas import pipelines and on the development of LNG facilities.

Pipelines

Options to import gas through pipelines include:

- Russia's east Siberia, in particular Kovykta field in the Irkutsk region;
- Russia's far east, in particular Yakutsk region in the Sakha Republic and gas supplies in the Sakhalin island;
- West Siberia *via* the Altai mountain to China's Xinjiang province. This is a highly speculative option.
- Central Asia, in particular from Ashkabad in Turkmenistan. This is also a highly speculative option.

Issues related to these options are discussed in more depth in Chapter 7.

LNG

LNG appears to be a more credible source of gas imports, especially for the coastal regions that are out of the reach of pipeline supplies. There are ample supply sources in the Asia-Pacific region and in the Middle-East which can adequately meet China's needs provided that the market can be developed accordingly. The country's first LNG importing project is under construction in Guangdong, and the first LNG cargo is expected to arrive in 2005. In the neighbouring province of Fujiang, another project is under preparation. There could be more LNG receiving terminals along China's east coast in the future.

Issues related to the LNG option are discussed in more depth in Chapter 8.

Future gas supply system in China

With all these domestic and import sources, China envisages an ambitious national gas pipeline system that would move gas from the west regions to the east and from the north to the south in the future. Map 4 of the report shows a possible gas supply system by 2020.

The system would consist of two main trunk gas pipelines: one is the North-South pipeline mainly based on imported Russian gas; the other being the West-East Pipeline and its associated branches. These trunk lines would be interconnected with the LNG importing terminals in east-coast provinces. The system would then link all the currently fragmented markets around the gas-producing regions. The initial proposed target which would seem to be very ambitious, is for the system to cover 21 provinces out of the total 22, four special municipalities and five autonomous regions by 2010.

GAS INDUSTRY STRUCTURE AND LEGAL FRAMEWORK

Historical background

Natural gas has been, and still is, considered part of the oil industry in China and has thus been largely eclipsed by oil. The current structure of China's gas industry is the result of the long evolution of the country's oil industry. Table 2.8 describes the changes that have occurred since the founding of the People's Republic in 1949. As can be seen, China's oil and gas sector has come a long way from the time when government ministries assumed industrial responsibilities to today's partially privatised national oil companies.

Table 2.8

Regulators and Industry Players in China's Oil and Gas Sector

Regulator		Industry Players
1949	Ministry of Fuel Industry (for oil, coal and power)	
1955	Ministry of Oil	
1970	Ministry of Fuel (oil and coal) and Chemical Industry	
1975	Ministry of Oil and Chemical Industry	
1978	Ministry of Oil	
1980	Ministry of Oil reporting to National Energy Commission which also oversees ministries of coal and power	
1982	Ministry of Oil reporting directly to the State Council. (National Energy Commission was abolished.)	Creation of China National Offshore Oil Corporation (CNOOC)
1983	Ministry of Oil	Creation of China National Petroleum and Chemicals Corporation (SINOPEC)
1988	Ministry of Energy (Ministry of Oil was abolished)	Creation of China National Oil and Natural Gas Corporation (CNPC)
1992	State Council via the State Planning Commission (Ministry of Energy was abolished, functions transferred to the SPC)	
1993	State Council via the State Planning Commission (State Economic and Trade Commission was established)	• Creation of ChinaOil, a JV trading company between CNPC and SINOCHEM (China National Chemicals Import and Export Corporation) • Creation of UNIPEC, a JV trading company between SINOPEC and SINOCHEM
1996	State Council via the State Planning Commission	• Creation of China National Star Petroleum Corporation (CNSPC) by the Ministry of Geology and Mineral Industry
1998	State Administration for Petroleum and Chemical Industries (SAPCI) under the State Economic and Trade Commission (SETC)	• Regrouping of CNPC and SINOPEC according to geographical partition to form CNPC Group and SINOPEC Group
1999-2000	State Economic and Trade Commission, with involvement of State Development Planning Commission (SDPC) (SAPCI was abolished in October 2000)	• Creation in 1999 of CNOOC Ltd by CNOOC; • Creation in 1999 and public listing in 2000 of PetroChina by CNPC Group; • Creation and public listing in 2000 of SINOPEC Ltd by SINOPEC Group; • Acquisition of CNSPC by SINOPEC Group in 2000
2001	State Economic and Trade Commission, with involvement of State Development Planning Commission (SDPC)	• Public listing of CNOOC Ltd

Source: IEA.

The most significant structural change in recent years was the 1998 industry restructuring, which defined China's oil and gas sector's map today.

The 1998 restructuring of China's oil and gas sector

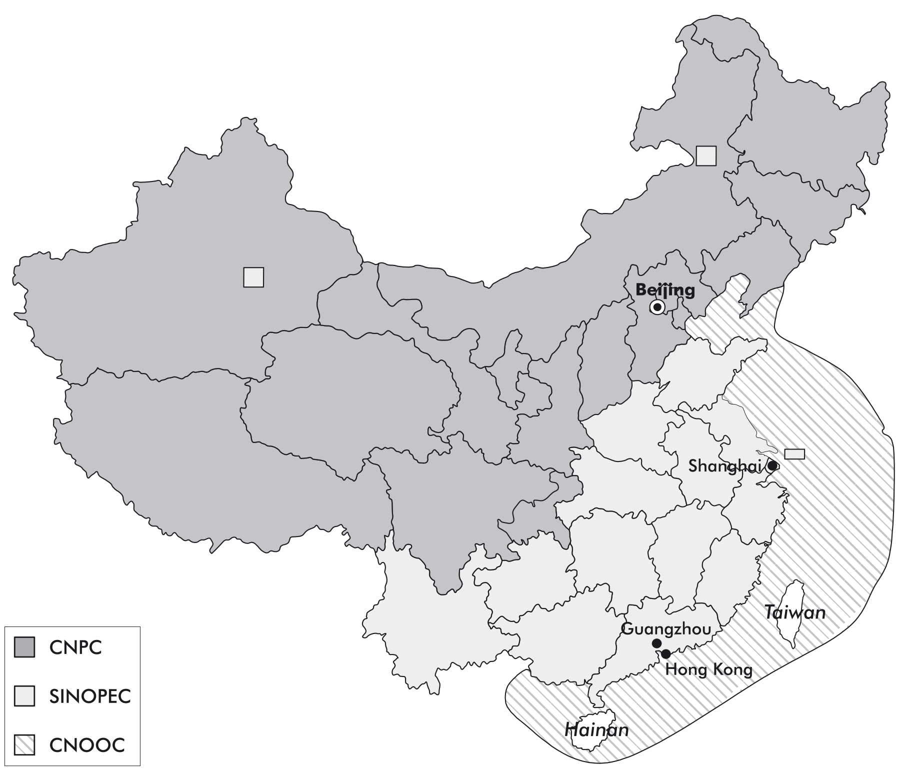
Prior to 1998, five domestic oil companies shared China's oil and gas sector:

- CNPC, which was established in 1988 on the abolition of the Ministry of Oil, had a quasi-monopoly of onshore upstream exploration and production.
- SINOPEC, created in 1983 by the Ministry of Oil, had a quasi-monopoly in refinery and other petrochemical activities.
- CNOOC, which was created in 1982 when China first opened its offshore acreage for foreign investment, was mainly involved in offshore E&P activities.
- CNSPC was much smaller than the above three companies. It was created in 1996 by the then Ministry of Geology and Mineral Industry (today's Ministry of Land and Natural Resources) and was operating in a few designated areas for oil and gas exploration and production activities.
- SINOCHEM (China National Chemicals Import and Export Corporation), together with its two joint-venture companies (ChinaOil with CNPC and UNIPEC with SINOPEC), had a quasi-monopoly in the international trade of crude oil and products.

The two largest companies – CNPC and SINOPEC – also had government functions in their respective areas.

Figure 2.12

Geographical Partition of Chinese Oil and Gas Companies after 1998



The 1998 restructuring concerned only CNPC and SINOPEC. The objectives and corresponding major restructuring actions were to:

- *Separate the functions of government and companies*: Government functions were taken away from CNPC and SINOPEC and transferred to a newly-established temporary agency – the State Administration for Petroleum and Chemical Industries (SAPCI), before they were finally transferred to the SETC in October 2000.
- *Integrate the upstream and downstream business to avoid duplicative construction of refineries and petrol stations*: Two vertically integrated domestic giant companies – CNPC Group and SINOPEC Group were created by an asset-swap agreement (E&P and transportation assets of CNPC against refinery and petrochemicals of SINOPEC). The swap was carried out in a way that effectively formed a north-south partition of the domestic onshore market (see Figure 2.12). Most provincial companies were regrouped into one of the two majors according to their geographical position. However, the agreement did not give exclusive rights to either company, therefore providing room for gradual competition.
- *Integrate domestic and international trade*: Both CNPC Group and SINOPEC Group were given full rights for international investment and trade, in synergy with their domestic trade activities.

Gas industry structure today

Gas exploration, production and processing

As a result of the 1998 restructuring of China's oil and gas industry, gas E&P and processing activities are now carried out by the following three companies:

- CNPC Group, mainly through its commercial entity PetroChina, which operates in the north and west of China (see Figure 2.12). PetroChina was listed on the stock markets of Hong Kong and New York in 2000. CNPC Group is the largest gas producer, accounting for two-thirds of China's total natural gas production in 2000.
- SINOPEC Group and its commercial arm SINOPEC Ltd., which operate mainly in the east and south of China. The acquisition in 2000 of CNSPC by SINOPEC Group, which was meant to strengthen the latter's E&P capability, also gave SINOPEC access to the areas located in the north and west of China and to areas located offshore. SINOPEC Ltd. was listed on the stock markets of Hong Kong, New York and London in 2000.
- CNOOC and its commercial subsidiary CNOOC Ltd., which operate offshore, mainly in the South-China and East-China Seas and the Gulf of Bohai. Its gas production accounted for 15% of the national total in 2000. CNOOC Ltd. was listed on the stock markets of Hong Kong and New York in March 2001, after a failed listing in October 1999 in Hong Kong.

High-pressure transmission

Currently the majority of onshore gas pipelines are owned and operated by PetroChina, and all the offshore pipelines are owned and operated by CNOOC and its JV partners, as shown in the following table.

Table 2.9

Ownership of Major (>300km) Domestic Gas Pipelines in China

Owner	Route	Diameter (mm)	Distance (km)	Capacity (mcm/y)	Year of completion
PetroChina	Sebei-Xining-Lanzhou	660	953	2,000	2001
	Jingbian-Beijing	660	865	3,000	1997
	Jiangbian-Yingchuan	426	313	500	1997
	Jingbian-Xi'an	426	489	800	1996
	Hejiangdong-Lianglukou-Foyin	720	313	2,880	1979
CNOOC	Pinghu-Shanghai	355	375	500	1998
	Yacheng-Hong Kong	700	787	2,900	1994

Source: Paik and Quan, 1997, and PetroChina.

Local gas distribution

Natural gas distribution is carried out by local (either provincial or city-level) companies, most of which are owned by local authorities. PetroChina, however, has a 20% stake in the Beijing Natural Gas Company. In most cases, the distribution companies were already selling manufactured town gas before the arrival of natural gas.

Gas imports (pipeline and LNG)

There is no imported pipeline gas as yet, but PetroChina is engaged in discussions to import Russian and Central Asian gas *via* long-distance pipelines (see Chapter 7).

CNOOC and its partners are currently building a LNG import terminal in Guangdong. There are plans to build several other terminals along China's east coast. (See chapter 8). But there is no law or regulation that makes CNOOC the sole LNG importer in China.

Existing gas-related laws and regulations

There is no law in China specific to either natural gas or oil. The legal framework governing oil and gas sector activities focuses mainly on the upstream. It consists of the following laws and regulations:

- "Mineral resources law" of 1986 and its 1996 amendments.
- "Rules for the implementation of the Mineral Resources Law", promulgated in 1996;
- "Regulations on registration over mineral resource exploration", "Regulations on registration over mineral resource exploitation" and "Regulations on transfer of exploration and mining rights". All of these regulations were promulgated by the State Council in 1998.

- "Regulations concerning the exploitation of offshore petroleum resources in co-operation with foreign enterprises", promulgated by the State Council in January 1982 and revised in October 2001.
- "Regulations concerning the exploitation of onshore petroleum resources in co-operation with foreign enterprises", promulgated by the State Council in October 1993 and revised in October 2001.
- Local laws and regulations by provinces, autonomous regions and large municipalities that are directly under the central government.
- Furthermore, there are some special regulations by the Ministry of Land and Natural Resources on oil and gas management. They concern registration, license, penalty, notification, etc.

Annex II of this report provides a summary of these laws and regulations.

For the midstream, there are two sets of regulations covering oil and gas pipeline safety:

- "Regulations for oil and gas pipeline protection", promulgated by the State Council in March 1989; and
- "Provisional rules for safety supervision and management of oil and gas pipelines", promulgated by SETC in April 2000.

Local gas distribution is mainly governed by the "Regulations on Urban Gas Distribution" published in 1998 by the Ministry of Construction.

Other general laws that can also apply to mid- and downstream oil and gas activities include:

- "Company Law"(1994);
- "General Principles of Contract Law" (1996) and its two separate laws for those contracts signed between Chinese legal persons and for those entered into by foreign entities;
- "Arbitration Law"(1995); and
- "Price Law" (1997).

KEY CHALLENGES IN DEVELOPING CHINA'S NATURAL GAS MARKET

To realise the ambitious target of gas market development, China must overcome a number of obstacles. These obstacles are briefly discussed below.

Gas demand build-up

The most important challenge is perhaps to develop the natural gas market from the consumption point of view. This involves the building of gas consumption facilities (power stations, petrochemical plants, boilers for industrial and commercial buildings, and household appliances). It also involves building new gas distribution systems or converting existing ones based on manufactured gas. Without all these end-using facilities, gas will not be consumed even when it is brought to the city-gate.

In China, the usual practice has been to build long-distance pipelines before making any serious effort to build the distribution infrastructure and to develop end-user equipment. This leads to low capacity utilisation for the pipeline and low returns for the investor. A case in point is the Ordos-Beijing pipeline, which went into operation in 1997 with a designed capacity of 3 bcm/y. However, it was built without much effort to develop the downstream market. Gas only started to flow in large quantities into Beijing two years after the completion of the pipeline, when the Beijing municipality government decided to switch all coal-burning facilities in the city to gas. Another case is the Sebei-Lanzhou pipeline, which went into operation in 2001, but the volume of gas flow one year later is still a fraction of the designed capacity of 2 bcm/y.

Lack of downstream market development jeopardises the economics of gas pipeline projects. When the Ordos-Beijing pipeline was built, gas use in Beijing was limited to residential uses. Although heating and industrial markets have subsequently been developed, there is still no stable gas demand in the city. Peak gas load in the winter is 5-6 times that of summer, which makes 80-85% of pipeline capacity idle during the summer months.

Building up the demand for natural gas in the distribution sector needs an active gas marketing approach, which is currently not being given sufficient attention in China (see Chapter 5). Gas-fired power generation provides an important anchor for large gas-pipeline or LNG projects, but things are not as simple as one may think despite all the advantages of this clean source of power generation. More issues on gas for power generation are discussed in Chapter 4.

Competitiveness of gas

One important factor for natural gas market development is the competitiveness of natural gas compared with alternative fuels, especially compared to domestic coal. The inherent advantages for household cooking, especially Chinese style, and the administrative restrictions on coal use in urban areas will push residential consumers to use natural gas with little short-term sensitivity to gas prices, although this may not be true for power plants and large industrial and commercial users. The price disadvantage of gas compared to coal may dissuade power generators and industrial users from making long-term commitments to using gas. Converting industrial and commercial installations will be particularly difficult if gas does not have significant price advantages, as people are already so used to their existing equipment.

Table 2.10

Competitiveness of Gas vis-à-vis other Fuels for Producing 10 MWh of Heat

Fuel	Price	Heat Value	Conversion Efficiency	Total fuel consumption	Total Fuel Cost
Coal	RMB 300/t	6,400 kcal/kg	14%	9,597 kg	RMB 2,879
Heavy Fuel Oil	RMB 1,800/t	10,000 kcal/kg	18.6%	4,623 kg	RMB 8,322
Diesel oil	RMB 3,000/t	10,000 kcal/kg	22.8%	3,372 kg	RMB 11,315
Electricity	RMB 0.522/kWh	860 kcal/kWh	33%	30,303 kWh	RMB 15,818
Natural Gas	RMB 1.8/cm	8,500 kcal/cm	26.4%	3,822 cm	RMB 6,898

Source: Beijing Market Study.

Table 2.10 shows the competitiveness of gas compared to other fuels for producing 10 MWh of heat in Beijing. It can be seen that natural gas costs 2.5 times that of coal to produce the same amount of heat. Market studies by the Guangdong Energy Technology and Economic Research Centre[6] showed that in Guandong province, imported LNG can compete with alternative fuels (bottled LPG and manufactured gas) in the residential sector, but cannot compete with coal and fuel oil in the commercial and industrial sectors. For industrial steam production, the cost of using LNG (at a regasified gas price of 1.65 RMB/cubic meter) is 75% higher than that of using coal and 40% higher than using fuel oil. For chemical uses, LNG cannot compete with domestic or imported naphtha, nor can it compete with chemical plants that are built at the well-head in gas producing countries. For power generation, LNG cannot compete with newly built large-scale coal-fired plants with desulphurisation equipment, nor with large-scale nuclear power plants.

Annex III of the report provides a case study of natural gas competitiveness and market development in Shanghai. It concluded that natural gas is competitive for residential energy uses against manufactured gas and electricity, and that it is cheaper to run buses on compressed natural gas than on gasoline. But at current prices, natural gas cannot compete with coal and heavy fuel oil for industrial steam production and power generation.

Gas pricing

The competitiveness of natural gas has much to do with the country's gas pricing policy.

China's gas pricing policy has been part of the overall gas allocation and control system. Although the volume of gas that is subject to this system is decreasing, the system is still in operation today. According to this system, a natural gas production quota is allocated by the State Development Planning Commission (formerly the State Planning Commission) to each producer according to the plan, and a volume is given to each of the key consumers (large fertilizer plants, major industrial consumers and major cities). The SDPC also sets gas prices. Over a very long period, the gas price for fertilizer plants has been kept very low so that its products are affordable to several hundred million Chinese farmers who have to produce enough food to feed more than one billion people. This system of government command and control has been blamed for hindering the development of a natural gas market as it eliminated the market role of prices adjusting to demand and supply.

Over the past decade, a number of steps have been taken in pricing reform, essentially to increase gas prices, but without corresponding measures and incentives to lower the cost of production.

If, in the past, producer and consumer prices for gas were so low that petroleum companies had no incentive to explore for and develop gas reserves, today, prices appear to be too high to provide any incentive for producers to reduce costs or for consumers to switch to gas. The

6 Source: Li Jianhua, "China's Energy Market and Role of LNG", presentation at the ABF China Gas Conference, 9 May 2002.

fact that the well-head price of gas in China is equivalent to the border prices of Europe's imported gas from Russia[7] suggests that there is room for cost reduction in the upstream sector. But another explanation could be that this high well-head price is the result of poor reservoir conditions in China's natural gas fields[8].

It is clear that a sound pricing policy for natural gas should be based on the market value of gas compared with other fuels. Issues related to gas pricing are studied in detail in Chapter 6.

Financing and investment

An enormous amount of capital investment will be required for China to build massive pipelines, LNG receiving terminals, combined cycle power plants, petrochemical plants, underground and other types of gas storage facilities, city gas distribution networks and related equipment and appliances, and to convert the existing network and appliances from manufactured to natural gas. Hence, meeting the expected increase in gas demand depends heavily on the successful financing of each individual project in the upstream, midstream and downstream sectors. This creates considerable uncertainty for gas demand projections.

For investors, domestic and foreign alike, China's gas market is certainly attractive as it is still in its infancy. But the market also presents important risks, which need to be appropriately mitigated for each individual project. Issues of gas infrastructure financing are discussed in Chapter 9.

Investments in gas exploration, production, pipeline construction and gas utilisation are now very much encouraged by the government. Its current oil and gas sector's five-year plan calls for multiplying sources of investment under the principle of "the one who invests takes the benefits". The urban gas distribution sector, which was closed to foreign investment until very recently, is now open on a limited scale. Issues on foreign investment policies and regulations in the natural gas sector are discussed in depth in Chapter 10.

Legal and regulatory framework

As described above, China has published a set of laws and regulations to govern upstream oil and gas activities. However, the legal and regulatory framework for the mid- and downstream is currently lacking. This creates uncertainties for investment and causes difficulties in conducting business related to gas transportation and distribution. There have been widespread calls for the country to publish a "Natural Gas Law" that would govern midstream and downstream gas activities. However, there still seems to be no consensus among Chinese policy-makers on the necessity and urgency for such a law. The World Bank is currently working with China on the downstream gas sector regulatory framework.

7 For example, the French border price of pipeline gas imports from Russia was US$1.87/MBTU in 1999 and US$2.43 /MBTU in 2000. For the same period of 1999-2000, the well-head price, including purification in China for the residential sector, was RMB 0.63/cubic meter (or US$2.12/MBTU) and that for commercial uses was RMB 0.88 /cm (US$2.96/MBTU).

8 Industry sources indicate that general reservoir conditions are much worse in China than in the major gas supplying fields to Europe, and that gas fields in China often have a permeability that is much lower than the permeability in some of the big fields in Europe/Russia.

Structure and regulation

Lack of competition due to the monopoly structure of the gas industry and the lack of transparent and unified regulation were considered key constraining factors in China's gas market development. Therefore, streamlining the structure of the gas industry and developing appropriate regulations also present a considerable challenge to the government.

Until now, natural gas has been considered part of the petroleum industry and its activities carried out mainly by the state-owned companies, including CNPC, SINOPEC and CNOOC. Gas development has not attracted much attention as most effort was directed at meeting the oil production target. This was considered a key reason for the low level of gas' share in China's energy mix today. It was only in the mid-90s that the policy of "paying equal attention to oil and gas" was adopted.

While China now struggles to establish the necessary infrastructure to build up the gas market, it also needs to adopt a regulatory structure that is most suitable to needs at this stage. However, long-term issues concerning the introduction of competition when the gas market becomes more developed also need to be addressed.

Gas policy and strategy

Policy practices that currently prevail in China's gas industry are characterised by regional regulations and a project-by-project approach. As gas production and utilisation only occur in a limited number of regions, regulations for gas activities are mainly defined by the relevant regional and local authorities. Disparities from one region to another are enormous. For most large projects, such as LNG importing terminals or long-distance gas pipelines, policies are developed on a project-by-project approach. While this approach provides flexibility to deal with the specific characteristics of each project, it also creates a lot of confusion, involves many bureaucratic administrations, and provides many opportunities for government interventions in projects that could normally be undertaken following normal commercial practices. The project-by-project approach seems to be the preferred policy practice in China, but it may ultimately prove to be very costly both in time and money.

Except for a brief statement of intent in the oil sector's five-year plan and some project-specific measures, China today does not have any clear and formal policy statement on natural gas, on its role in the energy mix, or on the accompanying policies and measures to encourage its development. This lack of a coherent government policy for natural gas has been widely blamed for the lack of progress of this clean fuel option in the country. It also creates uncertainties for international companies who wish to invest in China's natural gas projects.

As China reveals ambitious plans to develop a national natural gas market and as government officials at various levels call for the participation of private and foreign companies in developing the natural gas infrastructure, there is a widespread call for the government to publish a comprehensive natural gas policy to achieve the desired results. It is argued that such a policy should take an integrated approach to address issues of gas exploration, development, distribution, pricing, and marketing, as well as imports. It should also provide sound financial and fiscal conditions to attract private and foreign investment in natural gas projects, including project financing, bidding process, taxation, land-use, pricing, etc. Such a policy should be part of a coherent national energy policy, as China's gas industry is intertwined with the coal and the electrical power industry and with environmental policy. At present both gas and energy policies are lacking.

CONCLUSIONS

This chapter describes China's natural gas market – its current situation and future outlook. It also outlines a few key challenges facing the Chinese government and industry in meeting their target of developing a sizeable gas industry within a short timeframe. These challenges could be better tackled if best practices from international experiences are deployed so that pitfalls can be avoided. How should a strategic and policy framework for gas market development be defined? What are the implications from international experience? These questions will be discussed in the next chapter.

DEFINING A STRATEGIC AND POLICY FRAMEWORK: LESSONS FROM DEVELOPED GAS MARKETS

"Stones from mountains elsewhere can carve jade at home."
-Chinese proverb

Highlights:

- *The natural gas industry in general differs significantly from other energy industries and China's natural gas industry has an added unique set of features.*
- *China's strategy for developing the natural gas market is essentially a "supply-push" one. In order for such a strategy to succeed, it needs to pay particular attention to a number of issues, including the synchronisation of investment along the gas chain, the development of anchor projects, gas marketing and the end-use competitiveness of gas.*
- *This chapter reviews the experiences and lessons learned from gas market development in IEA countries, and assesses the implications for the elaboration of a market development strategy and a policy framework in China.*

Natural gas is recognised as the key to abundant and clean energy supplies in the 21st century. Not surprisingly, most governments around the world consider it to be the fuel of choice and are planning to dramatically increase its share in their respective national energy supply mixes. The APEC Ministers launched a "Natural Gas Initiative" in 1998 in order to accelerate investment in natural gas supplies, infrastructure and trading networks in the APEC region. In the European Union's green paper on energy security, natural gas is considered the preferred energy source. Many other regional initiatives are being undertaken in Latin America and South-East Asia to boost the supply and use of natural gas. China is no exception to this global enthusiasm for natural gas.

GENERIC CHARACTERISTICS OF GAS INDUSTRY AND MARKET

This type of strong enthusiasm is often accompanied by ambitious targets. However, it should not be forgotten that the development of natural gas markets has always been a long and challenging process. Gas market development needs a well-elaborated strategy and a sound policy framework that take into account both the generic characteristics of the gas industry and market, and the specific nature of the gas market in the host country.

Gas is different from coal, oil and electricity

Gas is significantly different from other energy sources. Unlike oil and coal, natural gas cannot be inexpensively stored in large quantities. Sophisticated and expensive infrastructures are required to deliver gas to the end user.

Unlike oil, gas transportation costs are very high. In general, transportation represents 50% of the total final consumer price compared to 5-10% in the case of oil. Additionally, the gas transportation and distribution system is relatively inflexible, because of the significant economics of scale involved. There is no world gas market – 85% of the gas consumed today in the world is produced locally. Thus, there is no world standard for gas pricing or marker price such as WTI or Brent for crude oil. Small gas markets are difficult to develop, and small gas discoveries are often hard to commercialise. As a result, there is a large amount of "stranded gas" in the world.

The most significant difference between oil and gas is that, unlike oil production for which investment can be made stepwise and usually precedes the conclusion of sales contracts, investment in gas production cannot go ahead without long-term commitment between prospective producer and consumer.

Although gas and electricity have the common feature of being grid-bound, which might suggest that these two industries can be regulated through similar approaches, they also bear significant differences:

- Gas is only produced where it is found, while electricity, except for hydropower, can be produced anywhere.
- With the exception of a few specific cases, gas can always be substituted by alternative fuels, which is not the case for electricity. This specificity of gas requires that the gas pricing policy take due account of the competitiveness of natural gas against competing fuels. It also has important implications for the regulatory approach. On the one hand, gas needs some sort of "protection" at the initial stage of development without which the market cannot develop; but on the other hand, if alternative fuels are available, the free choice of substitutes for gas is a very good protection for consumers, so gas may not be considered as a public service in the same way as electricity.

Gas industry works like a chain...

The gas industry works like a chain that links the well-head and processing plant to the transmission network, to the distribution network, and finally to the consumer. Each physical link corresponds to a commercial relationship. Each link is dependent on every other link in the chain and the overall strength of this chain is dependent upon its weakest link. As the whole network is vulnerable to disruption, firm and long-term relationships – in the form of "take-or-pay" contracts (see Box 3.1) – are likely to occur.

Box 3.1

"Take-or-Pay" Contract

A "take-or-pay" clause is usually included in a long-term gas supply contract. The latter normally includes the following four main components:

- Volume of gas to be delivered/off-taken over the contract's duration and the associated "Take-or-Pay" clause;
- The flexibility of the off-take;
- The price (initial price and indexation formula); and
- The price review conditions, which allow price renegotiation as well as their reference context.

A take-or-pay clause is an important tool to secure financing and to create confidence among investors and the lending community. Under a contract containing a take-or-pay clause, consumers are obliged to pay for the contract quantity of gas even if they do not actually consume it, thus guaranteeing the cash flows required by lenders.

Take-or-pay agreements have played a crucial role in gas market development around the world. However, reflecting the dependency of both buyers and sellers on the same supply chain, various additional terms have been introduced in order to make the clause more flexible:

- The take-or-pay obligation is only applicable to a specific percentage of the annual contract quantity;
- Some contracts contain a time period in which the buyer may take later delivery of the gas without penalty;
- The buyer is allowed to "make-up gas". These are gas volumes not taken but already paid for in one year. They are credited into the following years after having taken delivery of the annual contract quantity;
- The buyer may have a "carry forward right", which allows him to use past gas deliveries exceeding the annual contract quantity as a means to reduce his take-or-pay obligations in the following years.

Natural gas transportation contracts also usually contain a clause of "ship-or-pay" or "throughput and deficient agreement". Under this clause, the customer for whom the transportation is carried out is obliged to pay for the transportation of the gas, even if the gas is not actually transported.

...it needs huge investment....

The gas industry is very capital intensive: huge up-front investments are required to produce, transport, store and distribute gas. To produce the same amount of energy, gas requires 1,000 times the volume space of crude oil. The cost of long-distance gas transportation exceeds that of oil by a factor of 5 to 10. According to estimates by Exxon Mobil, to develop a 471 bcm per year gas market in Western Europe, 750 billion Euros were invested from 1960 to 2000 throughout the gas industry. This corresponds to 1.6 Euro/cm (or US$1.45/cm) per unit of gas development cost.

... in a co-ordinated manner

The timing of these investments is crucial: investments have to be made in a co-ordinated manner. In many cases, gas resources are far away from potential demand and the development of a gas market requires long-distance transportation. Field development and pipeline construction have no value unless local distribution networks and appliances are simultaneously put in place and transparent and predictable payment structures are set-up with creditworthy parties. At the same time, investors must ensure robust long-term financing as their revenues are likely to be subject to significant delays.

Gas market development takes time

It took 50 years for the share of gas in the world's energy mix to increase from 2% in 1900 to 10% in 1950. During this period, more than 90% of the gas was consumed in the US. Despite huge local resources and strong potential demand, the emergence of the US gas market faced important challenges. In Western Europe, natural gas was not consumed until after World War II and reached only 20 bcm in 1965. Four decades later, the natural gas market is still in varying degrees of development among the European countries.

Gas market is driven by paying demand

The last, but perhaps the most important point is that, unlike oil and coal, natural gas is not driven by production but rather by demand, more precisely by a demand that can justify all the investment along the gas chain. Resources and infrastructure alone are not sufficient, the market for end-uses must also be developed. Moreover, gas has no captive market and must compete with other energy sources. For example, in the residential and commercial sectors, gas competes with electricity, LPG and heating oil. In the industrial sector, gas competes with coal and oil in steam boilers. In the production of electricity, gas competes with coal, oil, nuclear, hydro, etc.

Special role of the state in the natural gas industry

Gas production uses natural resources that are part of the national assets. Gas transportation and distribution are linked to a fixed infrastructure using public land. It is a service which cannot easily be changed for small customers once they are linked to it. Furthermore, the transportation – and to an even greater extent – the distribution of gas have the character of a natural monopoly. Governments must establish rules in order to protect the economic interests of captive customers and to maintain the dynamics of competition under a natural monopoly. They should set rules for the gas industry to ensure that health, safety and environmental concerns are addressed. They should also issue permits or concessions and charge fees and taxes for the use of public land and resources.

For the above reasons, the state, either the central government or the local municipalities, used to manage gas supply activities in many countries. However, economic theory tells us, and experience shows, that the state is not the most efficient commercial player and that – notwithstanding exceptional post war/post crisis situations – the state is better off leaving the activities of the gas industry to private investors. Accordingly, in most countries the commercial role and the sovereign role of the state in the gas sector are being separated. The government's role is essentially to establish a framework for the gas industry that will stimulate investment, which will both protect consumer interests and provide a fair revenue for the state. This is particularly important at the early stage of gas development.

These generic issues must be considered in defining strategies for gas market development in China. Additionally, any gas strategy or policy framework needs to take into account the specific characteristics of China's gas market, as described below.

CHARACTERISTICS OF THE CHINESE GAS MARKET

As outlined in Chapter 2, China's current gas market has the following specific characteristics:

Main driver for gas demand is the desire to reduce environmental pollution

A key driving force for increased gas use in China is environmental protection, in particular the reduction of local atmospheric pollution. But important challenges remain before this potentially very powerful driver can become a real market mover. Other driving forces include the demand for higher quality fuel by an increasingly affluent population, the desire for diversification of the energy supply, and the opportunity gas provides to modernise industrial and commercial installations. Energy security, both in terms of reducing the country's overall oil import dependency and meeting a fast growing peak-load demand for electricity, is another important driver.

Main competitor is cheap domestic coal

Cheap and abundant domestic coal is the main competitor to gas, especially for power generation. Currently, the price of gas is 4-5 times that of coal for the same unit of heat. Given that China is the world's largest coal producer and that state-of-the-art power plants of 300 MW+ are manufactured within China, power generation based on coal has no effect on foreign exchange balance and keeps employment within China. This, together with the lack of domestic capacity to produce state-of-the-art gas turbines or combined-cycle gas turbines (CCGTs), leads to the difficulties of gas to compete with coal for power generation. In the industry sector, gas will also face sharp competition from coal and fuel oil.

Dominated by fertilizer production, the real gas market is very small

China's gas market is dominated by industrial demand, in particular for use as feedstock for fertilizer production, consuming around 40% of gas production. This, along with own-use by oil and gas fields, means that the commercial use of gas for energy purposes (power generation, industrial heating and residential/commercial sector uses) is very limited, accounting for only one third (or 10 bcm) of gas production. There is a potential market for gas heating in the north of China, otherwise the consumption of gas in the residential sector is low and confined to cooking and heating water. Nevertheless, many cities have an established grid of manufactured gas. Even though gas consumption by the residential sector is low, the price at which manufactured gas is sold is high, reflecting the willingness of consumers to pay more for a clean indoor fuel for cooking.

Residential use and power generation are the two main sectors that drive future natural gas demand. The residential sector can bear high gas prices, but its demand is not stable as there are daily and seasonal variations and its expansion takes time. Power generation can take a larger share of gas with a stable load in a relatively short time, but its economic viability depends critically on gas prices, on the way the power sector reform is structured and on the enforcement of environmental regulations. In large cities, the demand for gas and power in the residential sector tend to complement each other, especially during the summer when peak power demand corresponds to lowest gas demand.

Gas reserve conditions are poor and far away from potential demand centres

China's natural proven gas reserves range around 1.5 tcm, which are relatively large in relation to the current production level (27 bcm/y). The reserve/production ratio is high at around 55, reflecting insufficient capacity in production, transportation and downstream infrastructure. Theoretically, the resource base is even larger, but the lack of a mature gas market/firm customers discourages the search for more reserves. Most of the gas is consumed where it is produced, mainly in Sichuan Province for fertilizer production. Associated gas is mainly produced in oil fields in north-east China.

The bulk of gas reserves are located in the western and central part of the country, far away from major demand centres on the east coast. There is a large gas potential offshore, but substantial reserves remain to be proven. Furthermore, gas reserves are reportedly poor in geological terms and difficult to develop: there are not many large gas fields; only about 40% are relatively easy to exploit, but one third of onshore reserves are buried at between 3,500-4,500 metres and one quarter is below 4,500 metres. Half of the deeply buried gas has low or very low permeability.

Sources to boost gas supply are potentially important

Sources to increase China's gas supply include:

- Increase the output of existing gas-producing fields in Sichuan, Ordos Basin, South-China Sea, East China Sea, Gulf of Bohai and Qaidam Basin.

- Increase the use of associated gas produced by oil fields;
- Produce and use coal-bed methane;
- Increase production from the western region of China, especially from Xinjiang's Tarim basin;
- Import gas *via* pipelines from Russia's far east (Irkutsk's Kovykta field, Sakha Republic's Yakutsk and Sakhalin Island), and possibly from central Asia in a more distant future;
- Import LNG from Alaska, Australia, South-East Asia and the Middle-East to China's coastal provinces.

Physical infrastructure is still very limited

China's gas infrastructure, in terms of high-pressure transmission and low-pressure distribution networks, is very limited. Despite the efforts made in recent years to build some long-distance pipelines such as the Ordos-Beijing and Sebei-Lanzhou lines, there are still only isolated systems with no inter-regional gas grid connection, no cross-border gas imports and no LNG imports. Although most large cities have a manufactured gas network, they need to be converted to natural gas when it becomes available.

Clearly, the lack of infrastructure limits both demand and supply. Current projects to build the first LNG import terminal in Guangdong with the objective of bringing the first LNG cargo by 2005, and the construction of the 4,000 km West-East pipeline, represent a significant effort to improve gas infrastructure.

Huge need for investment

Assuming that it will cost about $1 billion to develop the upstream production, midstream pipeline and downstream market for each additional bcm/y of gas consumption, China would need some $40 billion from 2001 to 2005, $50-60 billion from 2006 to 2010, and about $80 billion from 2011 to 2020. Financing such an investment is an important challenge for China's gas industry.

Legal and policy framework is not yet in place

In addition to the physical characteristics described above, the following important policy and structural aspects of China's gas market also affect its future growth:

- The upstream and midstream operations are controlled by three vertically-integrated state-owned companies, while distribution is controlled by local companies owned by municipal governments.
- No single authority has regulatory oversight of the gas industry, and the regulatory framework is not yet clearly and consistently defined.
- China's electricity market is going through liberalisation and moving towards open competition.
- There exits no specific law on natural gas.
- The Chinese government does not yet have a coherent and formal policy statement on natural gas. Such a policy is needed to define the position of gas in the energy mix, the market structure, the role of private investors and the overall regulatory framework.

A transition economy

In structuring the legal and regulatory framework for China's natural gas industry, it is important to remember that although China is moving from its previous command-and-control economy toward a market-based one, it is a country with a strong tradition of central planning and government intervention. China's recent membership in the World Trade Organisation (WTO) will also require significant changes in natural gas practices, in particular with regard to enforceability of contracts, national treatment of foreign investors and transparency of regulatory procedures.

These specific characteristics distinguish the Chinese market from existing gas markets elsewhere.

Clearly, China's natural gas market is at its formative and growing stage. While China is actively building the physical infrastructure that is needed to boost supply and consumption, it is equally critical at this stage to have the appropriate strategic and policy framework to guide future gas market development. Such a strategic and policy framework needs to take into account the general characteristics of the natural gas industry and the specific characteristics of China's gas market. It should also refer to the best practices that have been proven elsewhere in the world, in particular those learned at a similar stage of gas market development. Learning from others' experiences and lessons can also help to avoid the mistakes made by others.

LESSONS AND EXPERIENCES FROM DEVELOPED GAS MARKETS

The first experience to share is the change of attitude towards natural gas in IEA countries (see Box 3.2). Initially, when the Agency was founded in 1974, natural gas was treated as a "noble fuel" with its use being encouraged to some premium markets such as residential and commercial sectors and chemical feedstock. The use of natural gas for industrial boilers and power generation was discouraged or even forbidden. This policy changed in the early 1990s, when all restrictions on gas use were lifted and gas became a "general commodity", subject to the rules of competition.

Box 3.2

Change of IEA Natural Gas Policy

In the early years, the IEA's interest in natural gas was modest and technical. Natural gas was viewed as a component of the oil industry that could be used essentially as a replacement for oil products in petrochemical feedstock. Gas use for steam production or power generation was discouraged, or even forbidden. On the other hand, the use of coal and nuclear power was encouraged.

The "Principles for Energy Policy" adopted by the IEA in October 1977 called for "concentration of the use of natural gas in premium users' requirements, and developing the infrastructure necessary to expand the availability of natural gas". Corresponding to this policy were the 1975 European Commission's Directive, which limited the use of gas for power generation, and the US "Power Plant and Industrial Fuel Use Act" of 1978, which prohibited the use of gas in new industrial boilers and power plants.

The interest for gas, however, was rapidly rising. In 1979, IEA Ministers regarded natural gas as the most readily available alternative fuel to oil and agreed on the need to encourage both indigenous production and international trade in natural gas. During the 1980s, the IEA gas policy focused immensely on gas supply security. Measures taken to improve security included the development of indigenous production, reduction of trade barriers, and the diversification of supply sources.

In 1991, IEA Ministers recognised that a commercial approach to the development of more open and competitive markets would ensure the exploration, development and production of natural gas resources. The "Shared Goals", adopted by IEA member states in 1993, encouraged the use of natural gas whenever the market would allow it. Corresponding to this new policy, all restrictions on natural gas use were lifted in the early 1990s in IEA countries.

Source: Richard Scott, *"The History of the International Energy Agency: 1974-1994"*, IEA, 1994.

From a regulatory point of view, the gas market developed along similar paths in most IEA countries. At the outset, the gas industry was heavily regulated from the well-head to the burner tip, whereas today it is a modern industry driven by a combination of regulation, competition and market forces.

The experiences and lessons in gas market development in the three main IEA regions (North America, OECD Asia, and Western Europe) are briefly described below.

United States: lessons from regulatory development

The United States has the oldest and largest gas market in the world. In 2000, gas consumption reached 638 bcm/y. About 84% of this supply is produced domestically, with the balance either imported by pipeline from Canada (15%) or through LNG imports (1%). The share of natural gas in the energy mix was 24%. The industrial sector is the largest consumer of natural gas (42%), followed by the residential and commercial sectors (37%) and electricity generation (13%). The remainder is consumed by the gas industry itself.

The US gas market is the most open (at the wholesale level) and mature market in the world. There are thousands of gas producers and millions of consumers. Gas production is concentrated in the south, along the Gulf Coast in Louisiana and Texas, with smaller producing regions in Alaska, the south-west, and central US. Though Texas and Louisiana consume large amounts of gas, most natural gas consumers are located in the northeast, the Midwest, and the Pacific coast, where Canadian imports play an important role. The geographic imbalance between producers and consumers means that large quantities of natural gas must be transported long distances across the country. The US has the most extensive gas pipeline system in the world:

330,000 km in 2000. Natural gas pipelines are privately owned, often by large corporations. Local distribution systems are also privately owned, usually by investors and municipalities.

The history of the US gas industry can be divided into the following four eras:

1910-1950: Era of market development

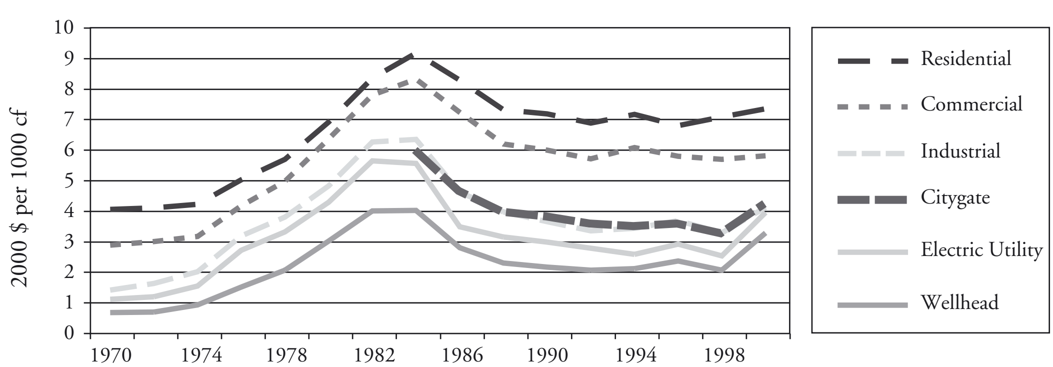
The US natural gas market emerged after World War I as a result of the huge gas resources from oil discoveries. It was able to develop because of the existence of large town gas systems and the industrial ability to weld steel pipes making it possible to connect new sources of supply with existing markets despite long distances. The structure was relatively simple. It was characterised by long-term contracts between producers and major consumers, short-distance field-to-city-gate pipelines owned by distributors, and the latter's franchise in exclusive areas under cost-plus state regulation. Nevertheless, economic and regulatory barriers remained, given that the gas industry was not regulated at the federal level but at the state level. This made it difficult to build and operate a pipeline across state borders. In order to overcome this barrier, the US Congress passed the Natural Gas Act in 1938 and established a federal regulatory body, the Federal Power Commission (which later became the Federal Energy Regulatory Commission, FERC) with the power to regulate interstate commerce, construction of pipeline facilities and transportation costs. Regulations were basically designed to ensure reliable supply at reasonable prices.

1950-mid-1970s: Era of regulation

The 1938 Act was amended by a Supreme Court Decision in 1954, imposing the regulation of prices at well-heads for interstate commerce. Unfortunately, prices were set too low (0.5 $/MBtu), which discouraged the development of gas resources. At the same time, gas demand was booming in the US economy. This resulted in a supply crisis during the winter of 1976-1977 in the mid-west and north-east.

Figure 3.1

Average Annual Gas Prices in the USA



Source: Energy Information Administration, US DOE.

Late 1970s – early 1980s: Era of regulatory failure

The 1978 Natural Gas Policy Act addressed the issue of low gas prices by providing incentives in the form of high prices for production from new gas or unconventional resources. A complex interstate pricing system was introduced which differentiated between expensive gas from newly developed fields and cheap gas from old fields. It also imposed different price ceilings on different gas supplies (up to 29 types of gases!). Since gas prices from new fields were based on costs plus a reasonable rate of return, companies had little incentive to operate efficiently. Gas production boomed, but a number of other problems were caused:

- First, gas prices were artificially raised, on average by a factor of 8 within a decade, which significantly curbed demand (see Figure 3.1).
- Second, the drop in gas demand[1], combined with the prohibition of gas use in new industrial boilers and electric power plants by the 1978 "Power Plant and Industrial Fuel Use Act", led to a surplus of gas supply or the so called "US gas bubble".
- Third, pipeline companies – which were allowed to buy gas at well-head, transport it through their own networks and sell it to customers – all contracted long-term take-or-pay agreements, and those contracts were based on largely over-estimated future gas demand. The significant drop in gas demand thus caused severe financial difficulties in pipeline companies as they were no longer able to take delivery of the contract quantities and sell them profitably. This led to a crisis of the entire gas industry in the 1980s.

Late 1980s – present: Era of adjustment/restructuring/deregulation

In the second half of the 1980s and throughout the 1990s, Congress passed new acts deregulating the gas industry and moving towards a more market-oriented approach.

- First, in 1985, the FERC adopted Order No. 436, which introduced open access to interstate pipeline transportation.
- In 1987, Congress repealed the 1978 Power Plant and Industrial Fuel Use Act, and in 1989 well-head prices were scheduled to be fully decontrolled by 1st January 1993 under the Natural Gas Well-head Decontrol Act.
- In 1992, the FERC adopted Order No. 636, which required interstate pipelines to unbundle natural gas sales from pipeline transportation by setting up separate affiliates to handle these activities. Order No. 636 also enhanced the method for calculating transportation tariffs and introduced a capacity release programme which forced incumbent companies to release pipeline capacity to competitors. The decontrolling of well-head prices and the two orders (436 and 636) dramatically changed the operation of the gas industry from tight regulation to free competition in the wholesale market, thus introducing the main principles that are now commonly applied in mature markets.
- In 2000, the FERC adopted Order No. 637, which further refined the remaining pipeline regulations and addressed inefficiencies in the capacity release programme.

1 US gas demand dropped by 21% from 1979 to 1987 because of high gas prices, more efforts in energy conservation, a series of warm winters, structural change of the US economy and declining prices of competing fuel oil.

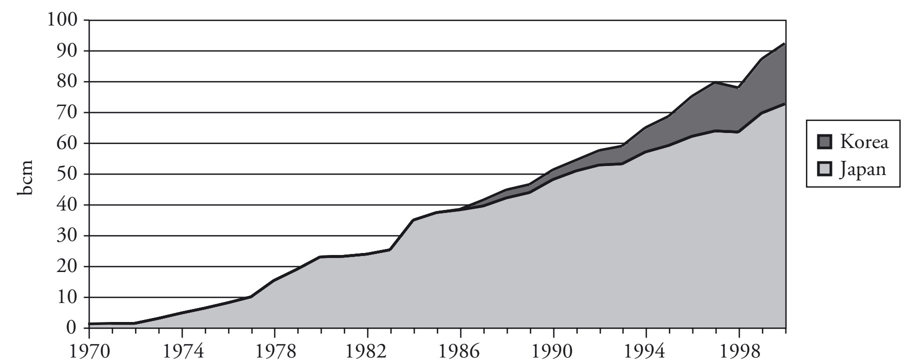
This policy of market deregulation was a success. Gas production has increased by a dramatic 31% since 1989 when well-head prices were fully decontrolled. After more than ten years of deregulation, the US market is fully liberalised at the wholesale level and is very competitive. Producers, pipeline companies, marketers, distribution companies and large consumers trade natural gas for immediate delivery and forward delivery in a large number of regional markets. Most trading takes place in spot markets at major market centres and hubs on interstate pipelines, the most important being Henry Hub in Louisiana. Based on trade of forward gas at gas hubs, financial markets for gas futures and options, the most widely traded futures use Henry Hub as a reference. Important trading activity also occurs in financial gas markets (futures and options).

The US example demonstrates how the regulatory framework plays a key role in the development of the gas industry: it may contribute to setting free the dynamic forces of competition or on the contrary it may inhibit its development. Regulation must be in line with the state of development of the market. Price-setting is the most difficult issue. The US experience also shows that there is a role for both government and market forces and that their respective roles must be clearly defined. Market forces should be allowed to prevail where competition is present. The correct role for government is to establish a framework to encourage investment in production and infrastructure development and to protect captive customers against the misuse of market power. Where competition exists, the market, rather than the government or regulators, is in the best position to determine price and allocation.

Japan and Korea: role of government for gas market development

Figure 3.2

LNG Imports in Japan and Korea



Source: IEA.

Like the United States, the gas industry in Japan and Korea started from coal gas. But unlike the US, both Japan and Korea have little or no natural gas resources. Given that there was no natural gas that could be imported through gas pipes, the natural gas industry has been built on LNG imports (see Figure 3.2).

Japan

Gas consumption in Japan reached 78 bcm in 2000. All gas consumed in Japan is imported under the form of LNG. Japan initiated LNG trade in the Asia-Pacific region in 1969 with its first imports of LNG from the US (Alaska) and has since grown to become the world's largest LNG importer and consumer. Today, LNG is imported from eight producing countries. In 2001, natural gas represented 13.4% of the country's TPES. Power generation is the largest consumer (65.6%), with the residential and commercial sectors consuming 20.6% and industry 13.8%.

As in the US, the gas industry in Japan began with the distribution of manufactured gas. Japan's natural gas industry was developed on LNG imports with power generation as an anchor. Large power plants were built next to LNG re-gasification units and the CIF (cost-insurance-freight) price of LNG pegged with prices for light sweet crude (which was used for power generation) so that natural gas was competitive for power generation. The first project was handled jointly by Tokyo Gas and Tokyo Electric Power Corporation (TEPCO) under strict environmental regulation by the local government. Take-or-pay contracts of twenty years duration and competitive pricing mitigated the risks of the long-term investments required in the gas chain from production, *via* liquefaction, LNG tankers and re-gasification. The government assisted the financing of the projects and promoted the use of LNG. The subsequent rapid increase in LNG imports reflected the government policy to diversify the economy's energy import base and to decrease oil dependency.

Several policies and measures were established to promote LNG use in other sectors. Gas companies benefited from a monopoly situation in their supply region. Price regulation guaranteed cost pass-through to the end user. Investors received low-interest loans through government-owned banks. A favourable taxation regime was put in place and subsidies were granted by the Japanese government, such as for the development of gas heating and cooling technologies.

LNG use in the industry and commercial sectors is promoted through strict environmental regulations to urban and suburban areas. Energy plans on building offices or factories have been established. Co-generation systems have been promoted in public buildings, hotels, hospitals, etc., and district-heating systems have been introduced in congested areas. In the residential sector, strict standards have been set and new gas appliances promoted. The "master plan" in city's development planning plays a significant role in the development of natural gas in the principal cities.

Today, the gas market is more mature and the Japanese government has introduced reforms intended to encourage competition in the marketing of natural gas to large industrial customers and to regional or local distribution companies. Japan has initiated the reforms through two amendments of the Gas Industry Law, which has regulated the gas industry since 1954. The first amendment in 1995 opened retail competition to large-scale consumers with annual gas demand of 2 million cm/year or higher. A second amendment in 1999 reduced the ceiling to 1 million. In addition, the amendment allows Japan's four regional gas utilities to sell gas outside their supply areas. The 1999 amendment also introduces Third Party Access (TPA) to the transmission pipelines of the four regional gas utilities (but not to the LNG terminals). The deregulated segment represents 30% of the city gas market and 20% of the power market. The deregulation of the electricity sector, which began in 2000, is also greatly affecting the gas market. Power and city gas companies can now enter other territories and businesses. The most active area for competition is Kansai, where Osaka Gas and Kansai Electric are entering each other's territories. Japan's Ministry of Economy, Trade and Industry (METI) plans to force gas suppliers to allow unrestricted TPA to their gas systems by March 2004. The move will apply to both the retail and wholesale gas markets.

Although Japan is the seventh biggest gas consumer in the world, it has no integrated gas transmission system and thus severely lacks the gas network needed to facilitate the nationwide growth of gas demand in other sectors than electricity generation. Further development of the gas market is constrained by the country's pipeline infrastructure: pipeline networks in Japan reach only 5% of the country's territory and further development of the grid is jeopardised by legal right-of-way issues and high urban density that very significantly increase the cost of pipelines.

Korea

Korea is the world's second largest importer of LNG. In 2000, gas consumption was 19 bcm, accounting for 9% of the country's TPES. The residential heating sector absorbed 38% of the total gas demand in 1999, followed by electricity generation (22%), industry (13.5%), public combined heat and power (CHP) plants (15%) and commercial and public buildings (9.5%)[2]. Thirty-two city gas companies supply gas to 7.2 million homes nationwide.

In 1983, the Korea Gas Corporation (KOGAS) was created as a state-owned monopoly for import contract, construction of terminals and pipelines, and development of the gas market. The first LNG tanker from Indonesia arrived in 1986. Initially, LNG displaced manufactured gas from coal. Import volumes have increased steadily, with supply sources from Malaysia, Qatar, Oman and Brunei under long-term contracts, and additional spot volumes from Australia and Abu Dhabi.

Unlike Japan, which focused on gas for power generation as the basis for market development, the Korean gas market was driven by both residential use and power generation. The remarkable expansion of the gas market, in particular for residential use, was achieved by the development of a government-subsidised natural gas grid, which opened the door to further development of the infrastructure. To encourage gas use for cooling, the government subsidised its use and placed a surcharge on summer electricity consumption. Strict environmental measures, introduced both before and after the Seoul Olympic Games in 1988, also favoured the use of gas. For example, promoters of large buildings are obliged to build gas-fired co-generation, and city buses now use compressed natural gas (CNG).

One particular feature of Korea's gas sector is the regular public announcement of the country's gas plans. Indeed, according to Korea's city gas business regulations, the Ministry of Commerce, Industry and Energy (MOCIE) should announce Korea's Long Term Gas Supply Plan every

2 Distribution loss represents 2% of the total gas supply.

two years. After the announcement of the first plan in 1991, KOGAS started the construction of national gas trunklines along national roads or railroads. Those plans, together with the "Combined Heat and Power Business Act" – which was published in 1991 to facilitate the co-generation business mostly in the residential and industrial areas – provided the long-term policy stability for the development of the country's gas market.

The government has announced plans to reform the gas industry following the July 1998 policy directive for privatising public companies. The objectives of these reforms are to improve efficiency in resource allocation, with competition to promote gas industry development and to enhance service quality and consumer choice. The Korean government proposes to introduce gas-to-gas competition by unbundling imports and sales activities from terminal/transmission operation and establishing an open access regime for receiving terminals, storage and the transmission network. Thus, KOGAS will be split into three companies: two privatised and one retaining the LNG terminals and transportation grid. In November 1999, KOGAS held an initial public offering selling off 43% of its equity and is now listed in the Seoul and New York stock exchanges. The Korean government has yet to finalise the privatisation schedule including all the accompanying measures (level of government shareholding, price determination, allocation of LNG importing contracts, regulatory institutions).

One important difficulty that faces the Korean government in implementing further restructuring of the industry is the fact that KOGAS has already been partially privatised and its shares listed in the stock markets. This means that the government will have to consult all shareholders in its reform plan to take into account their interests. China will face the same difficulty if the government wishes to implement further restructuring plans of the oil and gas sector, as all three main operators have already been partially privatised.

The development of natural gas markets in Japan and Korea is impressive, given the lack of domestic resources. Key success factors in both cases include:

- a large existing market of manufactured gas that has been switched to natural gas at a competitive cost;
- a significant development of gas-fired power generation that provided the critical mass to make gas economically viable and to improve the market power of buyers against foreign suppliers;
- long-term commitments contributed to the development of supply and demand;
- environmental as well as price regulations favouring natural gas played a significant role; and
- the governments' long-term energy and natural gas plans and promotional measures encouraged gas market development.

Western Europe: 50 years of success

Western Europe is an example of a growing gas market that initially relied on national resources before turning to natural gas imports from much further afield. Natural gas consumption in Western Europe was 471 bcm in 2000, representing 22% of TPES. The residential and commercial sectors are the largest consumers (41%), followed by industry (28%), power generation (15%), district heating and CHP (10%), with the remainder (6%) being used by the gas industry itself.

The maturity of individual gas markets differs from one country to another depending on the existence of domestic energy resources or the proximity of external resources, energy policy, climate conditions, etc., the two extremes being Greece, where natural gas has just been introduced and accounts for 6% of the energy mix and the Netherlands, a big gas producer and exporter where natural gas accounts for 47% of the energy mix. Along with Norway, the Netherlands and UK are the two largest European gas producers, but their gas market development and subsequent reform strategy differed significantly (Box 3.3).

Box 3.3

Market Development in the UK and the Netherlands

As a result of large gas reserves discovered in their backyards, the UK and the Netherlands both have highly developed gas markets, with natural gas accounting for 38% and 47% respectively of the total primary energy supply in 2000. While the Netherlands lies in the heart of the vast European gas network and exports 58% of its gas to neighbouring countries, the UK was only integrated into the continental European market when the Interconnector became operational in 1998. There are other marked differences between these two countries in the evolution of their gas industry structure:

In the UK, the gas market began to grow in the 1960s with the discovery of oil and gas in the North Sea. British Gas (BG), which was created in 1972 under the Gas Act, was the state-owned monopoly, which owned and operated all onshore infrastructure and had long-term exclusive take-or-pay contracts for gas supplies from effectively all offshore producers. Since the early 1980s, the UK gas industry has gone through a series of reforms involving the promulgation of a number of legislative acts:

- The Oil and Gas (Entreprise) Act of 1982, which separated out BG's production activities and abolished its legal monopoly purchase right for gas and provided for access to BG's infrastructure to be negotiated between BG and new entrants.
- The Gas Act of 1986, which provided the legal framework for the privatisation of BG and defined the threshold of potential competition in the supply to large customers, created the Office of Gas Regulation (Ofgas) to regulate the gas industry.
- The Competition and Services (Utilities) Act of 1992, which lowered the threshold of competition.
- The Gas Act of 1995, which split BG into two companies.
- The Utilities Act of 2000, which merged Ofgas with the Office of Electricity Regulation, which was established in 1990, thereby creating the Office of Gas and Electricity Markets (Ofgem).

The reform process, although long and painful, has brought very positive results: the massive inflow of private capital, lower prices[3] and more choice for consumers. It was only in 1998 that full competition was achieved with all consumers – including 22 million household customers – freely choosing their supplier. This was possible only under the specific circumstances of the UK market and cannot be easily achieved elsewhere: plenty of available gas reserves waiting for development, a rapidly increasing demand for power generation and an infrastructure that was largely in place and amortised.

Unlike the UK, the Netherlands implemented a flexible gas industry structure at the beginning of gas development. The Dutch gas industry began in 1959 with the discovery of the huge Groningen gas field (with economically recoverable reserves of over 2,600 bcm). Before gas production began in 1963, the government worked quite extensively with private partners to establish a structural and legal framework for the production, trade and transmission of gas. This was achieved through a parliamentarian memorandum (known as the "De Pous Memorandum", named after the Minister of Economic Affairs at the time), which laid down the "Gasgebouw" (or the "Gas Structure" in Dutch). The Gasgebouw allows public-private partnership for the production and sales of natural gas, which was the basis for granting the Groningen concession to a joint-venture company. The Gasgebouw involved a series of contractual agreements signed in 1963 that balanced public and private interests. These agreements include:

The "Agreement of Co-operation" between the State, Shell/ExxonMobil and their joint venture NAM, and EBN/DSM (two Dutch mining companies) on the co-ordination of production, transport, and sale of Groningen gas, as well as transport and sale of gas produced elsewhere in the country.

- The "Agreement between the State and Gasunie", which gave the Minister of Economic Affairs power over Gasunie, including its plans for gas sales and purchases, pricing practices and infrastructure expansion projects.
- The "Management Agreement between the State, DSM and EBN[4]".

In the early 1970s, the Dutch government developed a "small fields" policy that obliged Gasunie to buy in priority from small fields, which otherwise would not have been developed. However, the policy of allowing the Groningen field to act as a swing supplier at European level for a number of years increased the security of the gas supply in Europe.

It wasn't until 2000 that a Gas Act was promulgated to introduce competition and to transpose the EU Gas Directive into the Dutch national legislation. Prior to that date, such legislation wasn't necessary, although there had been an intensive consolidation process from the mid-1980s to the mid-1990s.

3 According to the National Audit Office of the UK, consumers have saved over one billion pounds on their gas bill since 1996. But part of the savings was due to falling oil prices in 1997-99, as gas prices were pegged to those of oil.

4 DSM and EBN are two national mining companies.

Figure 3.3

European Natural Gas Transmission System in 1970

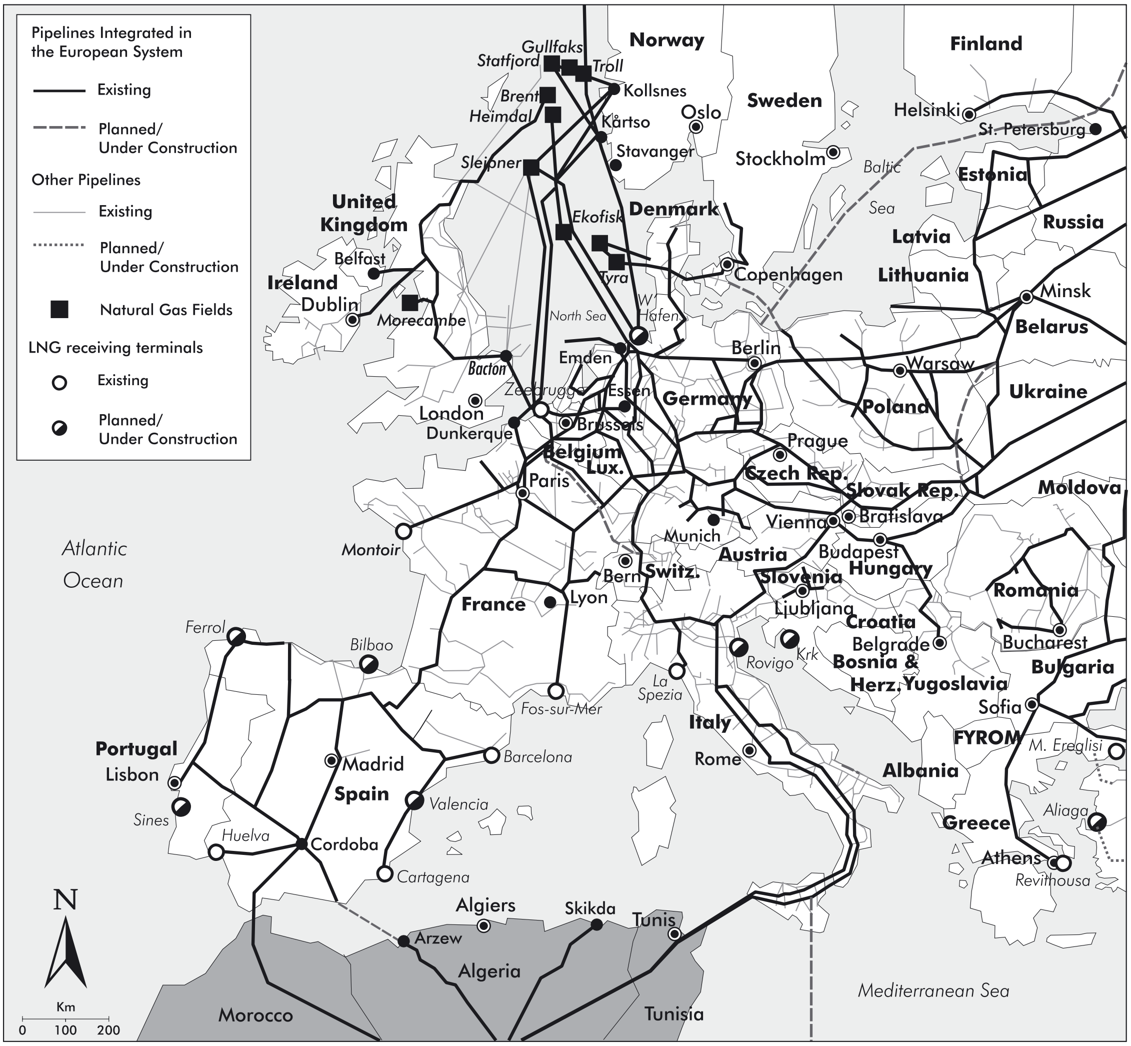
Source: Ruhrgas.

Although Western Europe represents the third biggest gas market in the world after the United States and Russia, it contains only 4% of world gas reserves. It was therefore necessary for Western European companies to import a large part of the gas consumed, first from neighbouring countries like the Netherlands and Norway, and later from more distant sources, such as Russia and Algeria. In 2000, Europe imported 40% of its gas from elsewhere (mainly Russia and Algeria). The European gas transmission system is continuously being expanded and upgraded, setting a good example of partnership and co-operation among corporate entities and countries.

The emergence and development of the natural gas market in Western Europe since World War II is in some sense in-between the cases of the United States and Asian countries. As in the US, Japan, and Korea, the distribution of manufactured gas was widespread in European

Figure 3.4

European Natural Gas Transmission System in 2001



Source: Ruhrgas.

cities. Natural gas resources were discovered in the 1950s in Italy, France and Germany. Local grids were built close to the gas fields, for instance in northern Italy (Pô valley), south-west France (Lacq) and neighbouring regions. Natural gas was mostly used to as a substitute for manufactured gas, which was well developed at the time. Each European state was strongly involved at that time as a regulator and as a market participant. The gas industry was heavily regulated. In general, the price mechanism was designed to compete with the market value of other fuels rather than to recover costs. This ensured that gas would find competitive outlets.

In the 1960s the natural gas market was booming in Europe, and demand exceeded national resource supply. The discovery of the giant Groningen field in the Netherlands led to the development of cross-border pipelines and proved to be a catalyst for the integration and development of the European gas industry. LNG regasification plants were built simultaneously in the UK, France, Italy and Spain to receive LNG from the newly built liquefaction plants in Algeria and Libya. However, the markets were mostly regional and based on the substitution of manufactured gas and fuel oil in the industry (cf. Figure 3.3).

The European gas market experienced a dramatic change in the 1970s with the development of the North Sea Continental Shelf resources and the opening of the gas routes from the former Soviet Union. Production began in the Norwegian North Sea after the first oil crisis, at a time when gas use was promoted to diversify the energy-import base and decrease dependency on oil. At the same time, the FSU, Algeria and the Netherlands intensified their gas exports. Investments in production, transportation and distribution were secured through long-term take-or-pay contracts and the competitiveness of natural gas was ensured through the net-back pricing approach.

However, in 1975, the European Commission adopted a Directive to limit the use of gas in the power sector and to reserve the gas supply for more "noble" uses, such as for residential and industrial consumers. Despite this directive, the amount of gas marketed in Europe jumped from 13 bcm in 1960 to 266 bcm in 1980. Gas consumption rose dramatically in European producing countries such as the Netherlands, the UK and Italy. However, power market consumption was limited and stagnant. The ban on the use of gas in power generation was lifted in 1991, reopening the power sector for gas. In the past decade, the use of gas in the power generation sector (excluding CHP) increased from 29 bcm in 1990 to 68 bcm in 1999, and is expected to grow significantly due to increasing environmental concerns.

Today, the European gas market is completely integrated from Siberia to the UK (cf. Figure 3.4). Gas penetration in the European market is now generally high, though with significant variations. Much of Europe is now a mature gas market; penetration of the industrial, commercial and household markets is high and can only be marginally improved, and the supply infrastructure is well-established.

The successful gas market development in Europe took place against the following background:

- the valorisation of significant gas resources within or close to Europe's borders;
- gas was cheap to produce, thanks to good geological conditions, while coal was rapidly becoming un-economic;
- the existence of important city gas distribution systems;
- a solid paying demand with guaranteed sales volume next to major gas reserves; and
- the rapid building of transportation infrastructure that linked production to consumption centres. Infrastructure development has been particularly impressive. In 1998, Europe had a total of 1,377,108 km of pipelines, including long-distance, high-pressure pipelines from production fields within and outside Europe and the low-pressure distribution networks.

The following factors, which form a particular market and policy framework in Europe, also contributed to the success of its gas development:

- Gas has been priced using the net-back approach (see Box 3.5 and Chapter 6) based on the replacement value (or opportunity cost) as compared with alternative fuels, and has been indexed to the price of oil. This arrangement guarantees that gas will be competitive with oil, thereby motivating and protecting investments in transport and upstream production, and encouraging end-users to switch from fuel oil to gas.
- Gas supply is characterised by long-term take-or-pay contracts between producers and downstream transmission/supply companies. This was also designed to protect heavy E&P and transport investment.
- There is a settled, somewhat rigid market/industry structure, generally consisting of producers, transporters and distributors. The last two own and operate the high-pressure and low-pressure networks respectively and also supply gas to end-users (power generators; industrial and commercial companies; and individual houses). However, there are significant variations between different countries in the number of companies carrying out these functions (for example, there are around 700 distribution companies in Italy, compared to some 30 in the Netherlands; 18 transmission companies in Germany, compared to just 2 in Italy).
- Ownership of the gas industry – particularly downstream – is predominantly public. Distribution companies are often owned by the local municipalities.
- Regulation is relatively light-handed. In many cases, downstream companies' pricing policies are constrained by regulatory controls on pricing and rate of return. Otherwise, the market regulates itself through a web of long-term, stable agreements between the market players, which are implicitly, if not explicitly, encouraged by governments. These long-term relationships rest on *de facto/de jure* monopolies or concessions. For example, the transmission companies generally have had a monopoly over gas imports into their national territory; and the distribution companies have had monopoly supply rights in their distribution areas. In short, until now there has been virtually no gas-to-gas downstream competition in Europe's gas markets.

Another critical success factor for European gas market development was the mutual trust that was built over time between companies and countries involved. This was partly achieved by the introduction of provisions contained in long-term contracts to adapt the contract provisions, principally the pricing provisions, to changing market realities by pegging gas prices to competing fuels prices, and by a regular review possibility to keep contract provisions reflecting market development. Even if practically all major gas contracts provide for a dispute settlement clause – usually arbitration – only a handful of disputes involving small volumes had to be decided by a third party.

This first phase of the development of the European gas market is, however, rapidly coming to an end. Driven by the belief that the gas market could be more efficient, and that the costs of gas supply and prices to end-users could be significantly lowered, the European Commission adopted a Gas Directive in 1998 (see Box 3.4). The Directive sets out the basic principles for reform, while giving countries some flexibility in transposing its provisions into national legislation. A main objective is to ensure transparent and non-discriminatory licensing for the construction and operation of facilities and for the supply to final customers, and minimum standards of accounting. The directive also provides for a progressive opening of European markets to competition. The choice of access regime (negotiated or regulated TPA), unbundling, and transparent tariff-setting are key aspects of reform. Upstream production issues like licensing or upstream prices or levies are not dealt with. A second Directive that would include more defined provisions and accelerate the liberalisation process is under preparation. Despite these Directives, the European gas market is not as open as the US market, given that Europe is not self-sufficient: an increasing share of European supplies comes from monopolies in Russia, Algeria and Norway.

Box 3.4

European Gas Market Reform

In May 1998, the Member States of the European Union adopted a Directive on internal gas markets, known as the "Gas Directive". This Directive is the baseline legal framework for gas market reform, but Member states can go further than the Directive's minimum provisions if they wish. It came into force in August 2000.

The Directive aims to create a competitive market in natural gas through common rules for transmission, distribution, supply and storage. Its key provisions are:

- *Minimum degrees of market opening, in three phases.* The initial market opening covers all gas-fired power generators and other end-users with an annual consumption of over 25 million cubic metres per year (mcm/y) and a minimum of 20% of each national market. The market opening widens to users with an annual consumption of 15 mcm/y and 28% of the market after five years from its effective date, and to 5 mcm/y and 33% after ten years.
- *Access to networks.* The Directive requires the opening of transmission network and storage facilities to third-party access (TPA), so that eligible customers can buy gas directly from producers if they so wish. It allows countries to choose between either a system of "negotiated" TPA with the publication of the main commercial conditions, or a system of "regulated" TPA, based on published tariff structures.
- *Regulator/dispute resolution.* The creation of an independent dispute settlement authority, especially with regard to system access, is required.
- *Unbundling.* Separate accounts must be kept for transmission, distribution, storage and (where appropriate) non-gas activities. The regulator/dispute settlement authority must have access to these accounts. In the case of regulated access and where access to the network is based on a single charge for transmission and distribution, accounts for these two activities may be combined. The objective is to avoid cross-subsidies, discrimination, and to ensure transparency and fairness.

- *Take-or-pay derogations.* A gas utility can apply to a Member state for a derogation from the network access requirements if it believes that it would encounter serious economic or financial difficulties because of its take-or-pay commitments in one or more gas purchase contracts. Applications are to be presented to the Member State on a case-by-case basis, either before or after refusal of access. The Commission may request that the Member State amend or withdraw a decision to grant a derogation.
- *Derogations for emergent markets.* Member States which can demonstrate that the implementation of the directive would result in substantial problems for the development of the gas market in an emergent region can apply for a derogation from the eligibility and licensing requirements for the construction of new lines. Such a derogation, which also requires Commission approval, may only be granted for a given area for the first ten years after the first supply to that area.
- *Public service obligations.* Member States are allowed, in the general economic interest, to impose public service obligations relating to security of supply, regularity, quality and price of supplies, and environmental protection on gas utilities

The European case provides a good example of a gas market based originally on internal resources, then later on resources supplied by long-distance pipelines and LNG imports. The emergence of the market was facilitated by the existence of city gas grids that were simple to convert to natural gas. And, as in Japan and Korea, long-term commitments helped attract the huge investments needed to produce, transport and distribute natural gas.

It also shows that the development of a mature market takes time: it took 40 years to develop an integrated European market. Market opening can only be envisaged when the market has reached a certain stage of maturity. This is one of the reasons why the European Gas Directive allows exemptions for emergent markets.

MAJOR IMPLICATIONS FOR CHINA'S GAS STRATEGY AND POLICY FRAMEWORK

The previous section of this chapter briefly summarised the experiences and lessons of IEA countries in developing their natural gas markets. There are also important lessons to be learned from other parts of the world, such as South America and South-East Asia, where gas markets are being developed. In South America for example, the opening up of the gas sector to private investment with a conducive regulatory framework has attracted the necessary capital and technology to undertake successfully a number of large gas pipeline projects, which would have seemed impossible only a few years ago[5]. Of course China needs to take these experiences and lessons and adapt them to its own specific characteristics in order to develop a strategic and policy framework for its gas market. China can also learn from its own recent experiences in developing the gas markets in Beijing, Xi-an and Shanghai.

5 See more South American gas experiences in *Gas in South America: Daring to tap the bounty*. IEA, 2002, forthcoming.

Strategic considerations

China already has some of the key drivers for gas market development, including the existence of a manufactured gas network, the growing need for clean energy, the desire to diversify the energy supply mix and the urgent need to reduce environmental pollution. But unlike Western Europe and North America, China's natural gas market development is in the context of poor gas reserve conditions and a plentiful supply of cheap domestic coal.

Pay attention to the pitfalls of a supply-push strategy

Many current aspects of China's gas industry development indicate that the country is pursuing a strategy of supply-push. These include the encouragement of gas production through successive increases of the controlled well-head prices, the practice of a cost-plus pricing regime for new projects, and the decision to build long-distance pipelines, such as the 4,000 km West-East pipeline for the East-China market, at a time when the demand was not yet confirmed. Such a strategy has not been tested elsewhere. International experiences show that the best strategy for market development is to first develop a local market and then bring gas in from long-distance sources when a sufficiently strong demand base is in place. For example, in Europe, gas from Russia and Norway was piped in years after the emergence of the natural gas market. This is the demand-pull approach, which has been proven to be successful in many parts of the world.

There may be domestic justifications for China to pursue a supply-push rather than a demand-pull strategy: without a strong push from the supply side, it is difficult for the demand side alone to pull gas market development, given the availability of cheap and abundant domestic coal. The fact that major domestic oil and gas companies play an important role in the government's energy policy decisions is also part of the reason.

For the supply-push strategy to succeed, special care needs to be taken to tackle the large number of important obstacles/issues that could jeopardise the objectives of market development. Those issues include, but are not limited to, the following:

- *Market development and competitiveness*: A supply-push strategy needs to pay special attention to downstream gas market development and the competitiveness of gas at various end-use sectors. International experience shows that a gas market can be successfully developed only if gas is priced competitively against other fuels. Proactive marketing policies are needed to promote the use of natural gas, especially for off-peak gas demand. This will involve the extension of city gas distribution networks, but serious obstacles exist (see Chapter 5) which, if not overcome, may seriously delay market development.
- *Synchronisation of investment*: Particular care needs to be taken to co-ordinate investments in upstream production and processing, pipeline construction and downstream distribution and consumption facilities. If the upstream or downstream investments are not made at appropriate times, either shortages of supply or a supply overhang (gas bubble) may occur. In either case, the emergence of a natural gas market would be jeopardised. International experience also shows that it is crucial to develop the gas-consuming market before the arrival of gas. Important lessons need to be learned from the Ordos-Beijing pipeline, where the lack of downstream investment and overall co-ordination seriously undermined

the economics of the whole project and caused huge losses for all players along the gas chain.

- *Development of anchor projects*: As the market for residential and commercial sectors is slow to develop, there is a need to develop large-scale gas-consuming projects such as large petrochemical plants and base-load CCGT plants to serve as an anchor for large gas infrastructure projects. A large amount of gas must be sold at the beginning to justify the investments in transportation. This implication is very significant for China and suggests that major pipelines will only become a reality when sufficient gas-fired power generation is allowed to guarantee an attractive return to investors. Only then can residential gas consumption be developed. But care needs to be taken to ensure that these anchor projects are commercially viable and that they meet the real needs of the economy over the long-term.
- *More realistic timing*: A gas-consuming market takes much longer to develop than the time it takes to build a pipeline. More realistic timing is needed in elaborating gas sector development plans.

In addition to these aspects that need special care, China's strategy for gas market development should also factor in the following key elements:

- *Systematic approach*: The gas industry should work out a number of critical elements of a systematic approach to gas market development: education and training of gas professionals, definition of gas quality, methodology for gas conversion, technical and safety norms and standards, etc. These elements are either missing or incomplete today.
- *Manufactured-gas distribution*: The existence of a coal-gas distribution network facilitates the development of the natural gas market. In expanding the existing manufactured-gas distribution system to cities which could be supplied with natural gas in the future, pipes that can adapt to future conversion should be used.
- *LNG imports*: Based on the experiences of Guangdong, LNG imports should be expanded to other coastal cities and provinces when feasible (see Chapter 8).
- *Pipeline imports*: Gas imports from Russia, in particular from Irkutsk, hold long-term promise. Earlier identification of markets and preparation of demand would facilitate the realisation of the project. Alignment of interests along any particular project will be needed (see Chapter 7).
- *Gas technologies*: Lack of domestic capacity in gas technology could hinder market development. China needs to develop and absorb those gas technologies, in particular CCGT and gas-fired co-generation of heat and power or poly-generation of heat, cooling and power. China should also actively participate in international efforts to develop new gas-using technologies such as fuel cell.
- *Gas-fertilizer swap*: Given that fertilizer production is a priority and that it currently consumes the major part of China's gas production, a strategic approach would be to look into the "gas-fertilizer swap". This consists of devoting newly-produced domestic gas to energy uses, and importing fertilizer from gas-rich countries. For example, India has taken this approach by building a fertilizer plant in Qatar while using its domestic gas for energy. It may be worthwhile for China to consider the same approach, as transporting fertilizer is much cheaper than transporting LNG.

Turn environmental protection into a real market mover

Given the imbalance between coal and gas in China, the success of gas market development depends critically on how seriously environmental protection measures are implemented at all levels by all players. Experiences from Japan and Korea show that strict environmental regulations and their rigorous enforcement can provide a big push for gas market development.

China has put in place a whole set of environmental laws and regulations on air pollution, but lack of adequate means for implementation makes most of them just paperwork. As noted in a recent World Bank report[6], the environmental agenda is so complex and large that it cannot be adequately addressed by the state environmental protection agency and its counterparts at lower levels working on their own. Furthermore, the systematic fiscal and budgetary problems facing the country as a whole make it difficult for environmental institutions to do their job – the gap between their assigned responsibilities and the resources at their disposal is growing. On the positive side, it is encouraging to note that the government has repeatedly promised to increase the budget for environmental activities and that new approaches and instruments, such as emission fees and emission trading, are being experimented. The government has also announced the objective of implementing the European air quality standards by 2005.

The penetration of natural gas into China's coal-dominated energy system encounters the same type of problems that are facing clean coal technologies and renewable energies. The development of these clean energy sources and technologies depends critically on the credibility of the country's environmental commitments and programmes. Significant work needs to be carried out in the area of institutional arrangements for dealing with environmental issues, in the area of the instruments applied to achieve environmental objectives, and in the area of investments made to underwrite environmental programmes.

To turn environmental protection into a real driver for gas market development, China needs first of all to define which market segments (e.g. residential, industrial, power generation) and which region (east China, north China) to target, study their specificities (e.g. demand characteristics, existing fuels, sensitivity to price and environmental regulations) and then elaborate a series of comprehensive measures for each market segment.

One important factor that affects gas-coal competition is the reflection of environmental benefits and costs into the economic equations. Since it is difficult to implement the imposition of emission fees related to coal use in the residential and commercial sectors, the country needs to rely on command and control administrative measures to replace coal by other fuels. It can also acknowledge the environmental benefits of natural gas by reducing taxes on natural gas (both commodity and infrastructure) and gas-using appliances, which would encourage the switch from coal to gas. If the government is serious about environmental concerns, it should waive or reduce all taxes and local charges on natural gas.

6 World Bank, 2001, *China: Air, Land and Water – environmental priorities for a new millennium.* Washington DC.

In power generation and industrial boilers, in addition to strengthening the enforcement of existing regulations, the use of economic instruments must be extended. To start with, the price/penalty per ton of emission (SO_2, NOx, particulate) should fully reflect the market value of emission permits and take into consideration the health damage to the public. It involves the following key areas of action:

- Fees should be applied to both profitable and unprofitable companies; they should be set according to the severity of pollution and should be extended to other pollutants (TSP, NOx and untreated waste water);
- SO_2 emission charges should be increased from the current level; each power company and each unit of a power plant should have an upper limit of SO_2 emissions per year;
- Fees should be indexed to inflation and should increase with time to remain a real incentive to reduce pollution.
- Fees should be independent of the fuel source: they should be imposed equally on power plants using low-sulphur coal or high-sulphur coal.
- Links must be severed between fees collected by local environmental protection bureaux and the use of these fees. Fees should be transferred directly to the General tax fund and should not be used either to fund EPBs or as loans to polluting plants.
- Based on the experiences gained from the trial phase, SO_2 emission trading should be formally established.

Although China does not have any CO_2 reduction commitment under the Kyoto protocol, the imposition of any carbon value, that is, the value for not emitting CO_2, would also improve the competitiveness of gas-fired generation against coal.

Policy, legal and regulatory considerations

International experience shows the importance of establishing an energy policy that encourages the use of gas and promotes investments in gas infrastructure and outlets, such as new gas appliances. Such a policy pronouncement is particularly effective in countries where the central government plays a critical role in gas market development, as in the case of Korea. Given that there is no clear policy on natural gas in China, the development of a gas policy should be a priority for the government.

Government's role in the gas market

The gas policy should clearly define the role of government in the gas market. International experiences show that although governments have an important role to play in developing the natural gas market, this role needs to be clearly defined. Governments around the world have all been involved in gas market development, either through ownership of state-owned companies, regulation of prices, negotiation of gas import projects, promotion of gas use through fiscal incentives and other measures. However, the government should not intervene by quantitatively allocating gas supplies or deciding on gas prices. The market does a much more efficient job than the government in these areas.

In general, the essential role for governments is to facilitate the evolution of competitive gas markets by promoting laws and enabling legislation designed to support the growth of an emerging market in the early stages, while embracing free-market mechanisms based on commercial principles in the long term.

Gas pricing

Pricing of natural gas throughout the chain from the well-head to burner tip is the key to a coherent gas policy. It is the most important and critical factor in emerging gas markets. The ability of gas to penetrate the market in China depends on its ability to compete with other fuels: coal in power generation, gasoil and LPG as an industrial fuel when clean fuel is required, and manufactured gas and LPG in the residential sector. Price therefore affects the volume of gas sold. End-use pricing is also of crucial importance for infrastructure development, because the revenues from sales to all categories of end-users will decide the viability of any natural gas project. The challenge is to find the right balance between what price the producer wishes to charge and what price the consumer is willing to pay. In addition, the pricing of the intermediate stages of the gas chain also needs careful consideration, and each link should be priced according to the risks involved. Outside of the gas value chain, gas pricing also needs to take into account the government's environmental and social objectives.

The government needs to reposition itself with regard to gas pricing. Each market around the world has its own unique set of supply, demand, transportation and alternative fuel characteristics, which together set the competitive price for gas. Even within a single market, there may be different prices depending on the type of service a customer requires. Market competition is always a more effective control on prices than any form of government price-setting. Governments need to intervene only where inter-fuel competition is unfair because pure market-based pricing does not take into account environmental impacts, or where there is a risk of monopoly power that could damage consumer interests. This could be done by a taxation policy in favour of gas, as in the case of Japan and Korea, or in the form of the regulation of gas distribution activities.

There are essentially two approaches to gas pricing: the cost-based (or cost-plus) approach and the market-based net-back approach. Box 3.5 illustrates these two gas pricing approaches. The cost-plus approach prices gas independently from alternative fuels. It encourages gas production, but does not take into account its end-use competitiveness and the final consumers' interests. It could work in countries where gas resources are abundant and cheap to produce. But it does not encourage efficiency improvements and is ineffective in sending accurate market signals to investors to stimulate competition. This explains why the United States and Canada have both abandoned this approach. The net-back approach links gas prices more closely to competing fuels. It guarantees the competitiveness of gas against competitive fuels, protects upstream and midstream investment and encourages fuel switching to gas. International experience demonstrates that net-back pricing is the best approach to gas market development, especially in a country without cheap and abundant gas reserves.

Box 3.5

Cost-plus Pricing versus Net-back Pricing

Cost-plus Pricing:	**Net-back Pricing:**
Well-head (regulated) price + Pipeline mark-up cost + Local distribution mark-up cost **= Sales price to consumer**	Market value of gas based on price of consumer's competing fuel – Distributor charges – Pipeline transportation charge **= Net-back price at the well-head**

As can be seen in Chapter 6, China's current gas pricing approach is predominantly a cost-plus one. Combined with the *de facto* monopoly of the three Chinese companies in their respective geographical areas, and with the future use of take-or-pay contracts, the continued use of this approach may lead to serious problems in the future. The reform of gas pricing in China should be directed at the adoption of a net-back pricing approach, based on the market replacement value. For this, the government needs to de-control the well-head and wholesale prices, as it would automatically lead to the adoption of the net-back pricing approach by market operators. Furthermore, gas sellers and purchasers should be allowed to establish mutually acceptable prices and terms through direct negotiations with each other, free from government interference or bias.

Long-term commitments

International experience shows that long-term off-take commitments through mechanisms such as "take-or-pay" contracts are critical to gas market development. But such commitments have certain preconditions: they can be effective only when the market is driven by demand and gas price is determined on the basis of its market value compared with alternative fuels. Without these preconditions, it will be difficult for China to obtain long-term commitments from gas off-takers if it pursues the supply-push strategy with a cost-plus pricing policy.

Legal framework

International experience demonstrates that gas projects can only come into fruition when the host government has built a legal framework that clearly and unambiguously defines acceptable rules of the game for all parties involved in the natural-gas chain. Such a framework should provide an adequate mechanism of profit-sharing between the upstream sector participants (i.e. E&P companies), the midstream trade and transmission companies, and the downstream distributing companies. It should also guarantee a certain level of protection to the end-user.

A sound legal framework provides the necessary basis for long-term commitments between market operators along the gas chain, which are essential for the successful development of the gas market. The legal framework should also provide long-term stability for investment in the gas industry.

Major capital investment decisions will be based on investors' expectations that existing contracts will be honoured and remain in effect for their full life. Long-term stability of the legal framework is the key. Continued stability, clarity and consistency of interpretation and avoidance of retroactive charges are essential to develop investor confidence. Such confidence is built up over time and is necessary to ensure that the large, up-front capital investments required for new gas infrastructure projects will be made.

It appears therefore that one of the most urgent tasks in China is to create a legislative framework that would facilitate the investment necessary to develop an interconnected national transportation grid and sustain strong future market growth. This needs to be conducted through wide consultation with all parties that have an interest, as well as careful, detailed analysis of and reflection on key issues. Short of a comprehensive national law on natural gas, China could consider the Dutch example (Box 3.3) of a more flexible approach at the initial stage, by having a set of legally-binding agreements between the government and all other involved parties.

Gas policy statement

New gas legislation would be the legal embodiment of the government's policy on gas industry development. But setting out primary legislation to deal with specific aspects of the mid- and downstream gas industry and navigating its passage through parliament is likely to take some time. In the meantime, the government should make a clear, formal statement of its policy on natural gas, including clear signals of how it intends to regulate different aspects of the industry. This could be achieved through, for example, the publication of a white paper on natural gas, which would set out the government's policy objectives and long-term strategy for development of the industry in the context of the current Five-Year Plan. The gas policy should also be backed by a consensus of stakeholders, including producers, pipeline operators, local distribution companies, and large and small consumer groups.

Regulatory framework

One important lesson from international experiences is that market regulation should correspond to the development stage of the natural gas market. Different case studies demonstrate clearly that market deregulation can happen only when the market reaches a certain level of maturity. It would certainly be counterproductive to replicate the regulatory models of mature markets such as those of the US and the UK as they are today, with their huge gas markets and multitude of suppliers. At each step of development, it is necessary to ensure that market forces are allowed to prevail in areas where competition is present.

The key question is which regulatory framework is appropriate for China to adopt for its gas transportation and distribution business, which is still at the infant stage of development. The primary objective of regulation in China is to attract and protect private investment in order to build up the gas market, given the enormous amount of capital that will be required. Such investment will be realised only if investors in gas infrastructure are convinced that there is a stable regulatory regime and that their investment will yield a sufficient rate of return. Consequently, regulations should be kept simple and straightforward, but should be reasonably stable over time. They should initially concentrate more on technical issues such as safety, environment, quality and metering standards. From the consumer side, regulations should focus on the protection of captive consumers from the abuse of market power by distribution companies.

The entire regulatory process needs to be transparent to all industry participants. Rate and tariff methodologies for services like terminal charges, pipeline transportation and storage need to be published in order to ensure non-discriminatory practices. Lastly, consistent oversight needs to be given to the entire gas value chain by a single authority which has jurisdiction over both the midstream (transportation and storage) and downstream (end use) sectors.

International experience also shows that when a gas market reaches maturity, competition in gas supply becomes desirable in order to maximise the efficiency of the sector. However, it is difficult to make changes to a monopoly system. This has been – and in some cases continues to be – a painful experience in many IEA countries. China could anticipate this problem by setting the groundwork for an eventual transition to full competition when creating its regulatory framework for initial monopoly rights. For example, serious consideration could be given to the access of the pipeline by a third party in the future, and the possible future unbundling of the different physical stages of the gas chain (production, high-pressure transport; low-pressure distribution). Issues of structural regulations will be difficult to resolve in the future if they are not properly set out at the beginning, as shown in the current case of KOGAS restructuring in Korea. More generally, Europe's current reform agenda, as described earlier in this chapter, could have a very practical relevance for China's regulatory framework if China's strategic objective is to ensure the long-term efficiency of its gas industry.

RECOMMENDATIONS

Based on the above analysis, the following recommendations are made:

RECOMMENDATIONS ON STRATEGIC AND POLICY FRAMEWORK

The Chinese government should:

- Make a clear and formal statement of the government's policy objectives and long-term strategy for natural gas in China through 2020. This could be done, for example, through a white paper on natural gas. More generally, work out an integrated national energy policy based on the completion of the 2001-2005 Five-Year Plan for the energy sector and the various energy industries.
- Prepare, as a matter of urgency, a legal framework on natural gas. Such a framework, which could take the form of a comprehensive national law or a set of legally binding agreements, should provide the legal basis for short-term gas market development activities, such as gas contract negotiations and enforcement. It should also be flexible enough to cope with market evolution over the medium- and long-term.

- Put in place a nationwide systematic approach towards natural gas market development, including such elements as education and training, gas quality definition, gas conversion methodology, technical and safety norms and standards, etc.
- Clearly define the role of government in the gas market to focus on the development of the policy, legal, and regulatory frameworks rather than on setting prices and managing individual gas projects. In designing the regulatory framework, anticipate the future need for third-party access and full competition when the gas industry has developed.
- Adopt the market-based net-back pricing approach as the basis for the use of take-or-pay contracts or develop similar types of contracts for long-term commitments.
- Promote switching to gas through financial incentives and environmental regulations, not only through mandatory purchase. Devise an incentive package (tax credits, depreciation rates, etc.) to encourage investment in gas.
- Increase investment in end-use gas technology development and in building domestic capability for absorbing advanced gas-using technologies.
- Pay close attention to the strategic issues discussed in the preceding section of this chapter. They include:
  - Adequately time/synchronise upstream, midstream and downstream infrastructure investment activities.
  - Strengthen efforts in downstream gas market development.
  - Where economic conditions justify, promote base-load gas generation or large gas-based petrochemical plants as a way of improving the viability of the West-East pipeline and the first phase of the LNG import project.
  - Develop new LNG importing projects as a way of developing local gas markets, based on market needs and feasibility studies.

GAS FOR POWER GENERATION

Highlights:

- *The combination of rapid growth of electricity demand and the desire to reduce environmental damage caused by the power sector provides real potential for gas-fired power generation. Gas-fired base-load generation also provides an anchor for the development of gas infrastructure projects. However, in many regions of China, gas is currently not competitive against coal, which is generally abundant and cheap.*
- *The viability of gas-fired generation depends critically on the implementation of policies and measures that will reflect the environmental costs of coal relative to gas.*
- *Given that large-scale CCGT plants can hardly compete with gas-fired ones for base-load generation, China should consider opting for small and medium-sized gas-fired units in the 10-50 MW range, which are almost as efficient as large units. In addition, a higher percentage of their waste heat can find useful applications. The current campaign and future plan of closing down small coal-fired power plants (less than 50MW) provide a good opportunity to replace them with gas-fired units.*
- *Distributed generation based in even smaller gas-fired units shows strong potential in the long-term, but needs to overcome a number of obstacles, in particular the possibility of feeding in surplus electricity and receiving back-up power from the grid at reasonable prices.*
- *China is in the process of establishing a competitive power market. In a competitive environment, generators will inevitably choose the cheapest source of supply unless they are obliged to do otherwise. China should not miss the unique historical opportunity offered by the current reform of its power sector to introduce measures in favour of clean power sources including renewables, gas, and clean coal technologies.*

TRENDS AND PROSPECTS IN POWER GENERATION IN CHINA

Past trends

Over the past 20 years, China's electricity production has grown significantly. Both installed capacity and production volumes in 2000 were about five times those of 1980, representing an annual growth rate of 8.2% and 7.9% respectively (Table 4.1).

Table 4.1

Evolution of China's Power Capacity and Generation (1980-2000)

	1980	1990	1995	2000	Annual Growth Rate
Installed capacity (GW)	65.9	137.9	217.2	319.2, of which: • Conventional thermal: 237.5 • Nuclear: 2.1 • Hydro: 79.3 • Other renewables: 0.33	8.2%
Total generation (TWh)	301	621	1,006.9	1368.4, of which: • Conventional thermal: 1,108 • Nuclear: 16.7 • Hydro: 243 • Other renewables: 0.7	7.9%

By the end of 2000, China had an installed capacity of 319 GW and an annual electricity output of 1,368 TWh, both ranking it second in the world after the United States. Conventional thermal power plants – more than 90% of which are based on coal – provide 75% of the total capacity and 81% of total generation. Oil-fired generating capacity totalled 17.3 GW (1997 data), half of which is located in the southern province of Guangdong (9 GW).

Despite the large volume of total installed capacity and generation, actual per capita power consumption in China was only 1,078 kWh/year in 2000, or half of the world's average and one eighth of the OECD average, which leaves a huge potential for future growth in electricity demand. The electrification rate is very high for a developing country: official Chinese data suggest that as of 2000, there were only 5.7 million households, or 23 million people (less than 2% of the total population), who had no access to electricity.

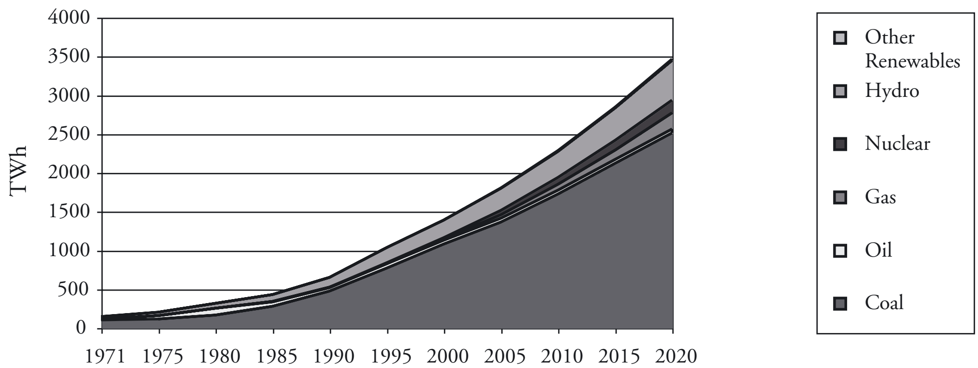
Future prospects

In the 2002 edition of the *World Energy Outlook*, the IEA projected that China's electricity demand would grow from 1,368 TWh in 2000 to 3,461 TWh by 2020, representing an annual growth rate of 4.7%. Total generating capacity is projected to reach 517 GW by 2010 and 787 GW by 2020. Coal is expected to meet more than two-thirds of the projected increase in electricity demand. Natural-gas-fired generation will increase from 7 TWh[1] in 1997 (0.6% of total) to 101 TWh in 2010 and 209 TWh (6% of total) in 2020, but these figures were cautiously termed as uncertain because they depend very much on the availability of gas infrastructure and price competitiveness.

1 The IEA figure includes only utility gas generation.

Figure 4.1

IEA Projection of Chinese Electricity Demand



Source: IEA, *World Energy Outlook*, 2002 edition.

The Chinese official target formulated as part of the 10th Five-Year Plan is to have 390 GW of total installed capacity by 2005. This is more or less in line with the IEA projection of 517 GW by 2010[2].

Demand growth will be uneven among the different Chinese regions. Figure 4.2 provides an electricity demand forecast by region. It can be seen that while demand will grow in all regions, the growth rate is strongest in the east region, the north region and Guangdong province.

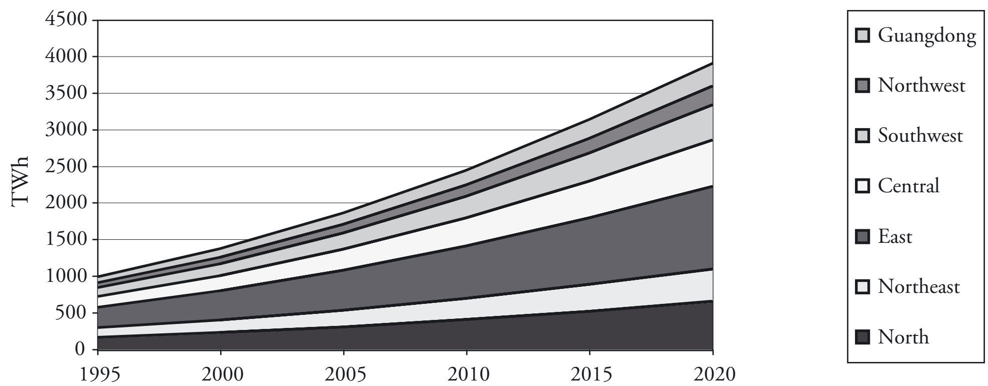
All these projections show that there is sufficient room for gas-fired power generation to form part of China's overall power generation capacity. However, given the growing electricity demand, even if gas is to be widely used in power generation, it is unlikely to take a dominant share in China's total generating capacity.

While the bulk of the additional electricity demand will be met by coal, as shown by the IEA's "business-as-usual" projection of China's power supply mix (Figure 4.1), diversifying away from the coal-dominated supply structure is a key priority of the government's policy in the power generation sector. Measures to achieve this, as set out by the 10th Five-Year Plan, include active development of clean energy sources, including hydropower, natural gas and other renewables, and "appropriate" development of nuclear power. In parallel with the west-east gas transmission project, China is also pursuing a vast programme of west-east electricity transmission in order to bring a large volume of hydropower from south-western and central parts of the country to the east-coast provinces (see Chapter 1 for more details).

2 A recent report by the World Bank also provided a projection of total generating capacity at 410 GW in 2005 and 550 GW in 2010. See World Bank, *Liquefied Natural Gas in China: Options for markets, institutions and finance.* Discussion Paper No.414, May 2000.

Figure 4.2

Regional Electricity Demand in China



Source: ERI/SDPC and Murdoch University, 2001. *China: Energy Policy and Natural Gas Use*, Asia Research Centre, Perth, Western Australia, p.24.

POTENTIAL FOR GAS-FIRED POWER GENERATION

Current situation

Until now, natural gas has not been used extensively for power generation in China. The most significant gas-for-power project is the "Yacheng 13-1" gas field in the South China Sea for power generation in Hong Kong, where a combined-cycle gas turbine (CCGT) plant of 1.9 GW consumes 2.7 bcm of gas per year. In mainland China, total installed natural gas-fired generating capacity was 7.2 GW in 1999, which was spread over 80 small gas turbine plants, and represented less than 2% of total generating capacity. Nearly all electricity generated was for own-use by large industrial firms that are located near the oil and gas fields. Utility use of natural gas was very small, mainly involving generators with an installed capacity of 50 MW or less. In 1999, power generation consumed 1.4 bcm of natural gas, accounting for 5.8% of total natural gas consumption. In 2000, only less than 1% of PetroChina's gas was sold for commercial power generation.

Why China needs gas-fired generation

In assessing the potential for gas-fired power generation in China, the first issue to be addressed is whether there is a need to develop gas-fired power generation in China at all, given the current limited availability of gas and gas-fired generating technologies and the abundance of the country's coal and hydro resources. Answers often tend to evoke the advantages of gas-fired generation over other fuels in OECD countries (see Box 4.1).

Box 4.1

Advantages of Gas-fired Power Generation in OECD Countries

Gas is often the preferred fuel for power generation in OECD countries. Gas-fired generation, mainly in combined-cycle gas turbines (CCGT), is projected to meet 76% of their incremental electricity demand between 1997 and 2020. The predominance of natural gas is explained by a number of advantages over other fuels including coal, oil, nuclear power and hydropower:

- *Lower investment cost*. In OECD countries, per kW investment cost of a CCGT plant is only half that of a typical coal-fired plant and is much lower than that of nuclear or hydropower stations. This, combined with the relatively low price and the abundant supply of gas in countries like the US, the UK, and the Netherlands, makes gas the cheapest option for power generation compared to coal and nuclear in such OECD countries.
- *Higher energy conversion efficiency*. CCGT plants can typically achieve 50-55% of nameplat efficiency with the highest level of 60% being tested, whereas the best coal-fired power plant can only achieve an efficiency level in the range of 40-45%.
- *Lower level of environmental emissions*. Replacing a coal-fired generation plant with a gas-fired combined cycle unit can eliminate SO_2 emissions, cut CO_2 emissions by two-thirds, cut NOx by 95%, reduce particulate matters by 99% and eliminate solid waste. Table 4.2 provides a comparison of environmental emissions from a coal-fired plant and a gas-fired plant.
- *Other technical advantages* including:
  (a) short lead-time in construction (2-3 years compared to 4-5 years for coal and 6-10 years for nuclear);
  (b) modularity and low economics of scale, meaning that small units could have the same economic advantages as large units;
  (c) flexibility for load management as gas-fired units can be used both for base load and peak load, and their ability to start and stop quickly make them excellent means for peak shaving; and
  (d) smaller requirement for land occupation and cooling water, which, together with their cleanness, allows their installation in densely populated areas.

Table 4.2

Emissions in New Power Plants (grams/kWh)

Plant Type	SO_2[a]	NOx	TSP[b]	CO_2
Pulverised Coal (PC)	11	3	0.2	857
PC w/ Wet Flue Gas Desulphurisation	1	3	0.2	893
Integrated Gasification Combined-Cycle	0.5	0.3	0.05	755
Heavy Fuel Oil	16	1.5	1.0	714
Natural Gas Combined-Cycle	~0	0.5	.03	336

a – Assumes 1.2 per cent sulphur content for coal.
b – Assumes fly ash removal efficiency of 99%. Solid waste of 74 grams/kWh is also produced by coal-fired plants.
Note: TSP = total suspended particulates.
Source: Logan, 1999.

While many of these advantages are valid for China, the following facts may raise doubts about the future role of large-scale gas-fired plants. China is endowed with abundant coal reserves which can be produced cheaply with inexpensive labour; it has the ability to domestically manufacture large-scale (300 MW) pulverised coal-fired plants; gas supply is currently limited, its prices are relatively high, and China does not have domestic manufacturing capacity of gas turbines or CCGT plants. Therefore the economic rationale for building large-scale CCGT plants may not be valid in China. Indeed, some Chinese researchers believe that China should learn lessons from its past "oil for power" programmes[3] and that gas should not be extensively used for power generation, but should rather be reserved for premium market segments such as residential and commercial use in urban areas and industrial chemical production.

The generic advantages of gas-fired power generation as described in Box 4.1 need therefore to be combined with the specific conditions of the Chinese gas and power markets in order to be justified. Those specific conditions are described below:

Need to provide large off-takes for important gas projects

Urban residential and commercial sectors constitute a premium market for gas, but demand in these sectors is subject to daily and seasonal variations which affect the economics of both transmission and distribution systems. Furthermore, the market in both sectors needs time and investment to develop. Power generation can absorb large quantities of gas with a short lead-time. Table 4.3 shows the time and money needed to develop one bcm/y of gas consumption capacity in the residential and power sectors. Large volume gas pipelines or LNG import terminals need large off-takers, at least initially, to justify their commercial viability.

3 China has launched two oil-fired power generation programmes. The first one was launched in 1970 and built a total generating capacity of 10.5 GW (16% of the country's total) in 1979, but the sharp oil price increases after the first oil crisis obliged the government to implement a control programme in 1976. The second programme was launched in the mid-1980s, when an economic boom of the coastal provinces caused serious power shortages, justifying a need for oil-fired generation plants to ease the power supply situation. However, the oil price increases in 1999-2000 have rendered many of those oil-fired plants inactive.

Table 4.3

Cost and Time Needed to Develop One bcm/y Gas Market

	Power plant	Urban residential sector
Cost of creating demand/bcm/y	$320 million*	$600-1200 million
Time needed/bcm/y	3 years	5-10 years

* CCGT plant of 600MW with construction cost of $530/kW and running at 8,000 hrs/year.
Source: IEA analysis.

New gas-fired power plants can provide anchors for projects such as the West-East Pipeline or the Guangdong LNG terminal. Indeed, according to industry sources, 40-50% of the West-East Pipeline gas and 60% of the first phase of Guangdong LNG project are scheduled for power generation. In parallel to the establishment of anchor projects, distribution systems should be developed to supply gas to industries, commercial enterprises and households. Use of gas in more decentralised power generation in urban areas would also promote the construction of the gas distribution system.

Need for peak-shaving capacity

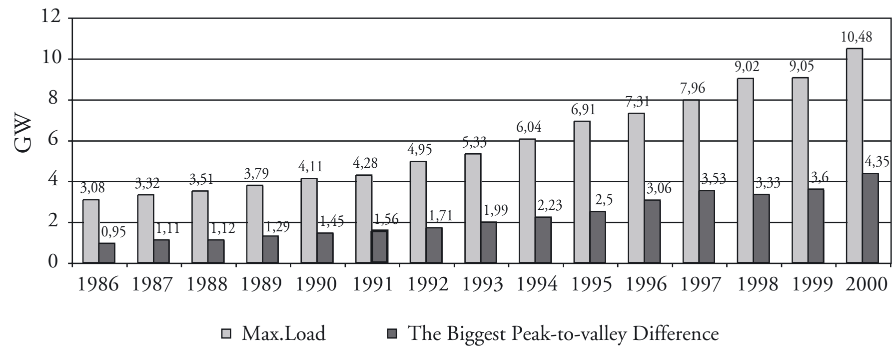
Over the last few years, China's peak electricity demand has been growing very rapidly, outpacing the increase of the total installed generating capacity. The rapid increase of peak load and the widening gap between peak and base load have caused the average load factor of power plants to fall rapidly[4]. Figure 4.3 shows the growth of peak-load and the widening gap between peak and base load in the Shanghai region. Other regions face similar problems.

One important driver of this growth is the rapid increase in the ownership of electrical appliances, in particular air conditioners. As can be seen in Table 4.4, the ownership of air conditioners is already very high and is rapidly growing. China now sells about 15 million air conditioners every year. If every appliance uses 1 kW (Chinese-made air conditioners usually consume between 1.5 and 2.5 kW) and all are switched on at the same time, then air conditioners alone (representing 15 GW) would absorb the major part of the annual increase of generating capacity (20 GW/y). As a result of the increased use of air conditioners, peak electricity demand rises in strong correlation with temperature during the summer, and many cities, including Beijing, suffer from power cuts because distribution networks cannot meet demand.

4 The average load factor of China's power plants dropped from 5,233 hours/year in 1994 to 4,350 hours/year in 1999. According to the State Power Corporation, 20 GW of installed generating capacity had only a few hundred hours of operation during the peak load period in 1998.

Figure 4.3

Growth of Peak Load Demand and the Peak-Base Gap in Shanghai's Power Grid



Source: Tongji University, 2002.

Table 4.4

Ownership of Air-Conditioners in Chinese Cities in 1999
(number of units/100 households)

Shanghai	Guangdong	Chongqing	Tianjin	Beijing
85.2	83.5	74.3	59.8	49.9

Source: Tongji University.

Another serious problem is daily peaks, caused by industrial and domestic uses. Currently there is no strong incentive for consumers to reduce their consumption during peak times or to invest in technologies to increase energy efficiency. Time-of-day pricing – to manage the increasing gap between peak and base loads – is rarely used, and when used, the price difference is too small in many cases to have a lasting impact on end-users' consumption habits. Lack of investment in transmission and distribution systems and poor inter-regional grid connections add further difficulties in meeting peak-load demand[5]. Decentralised power generation in small units may be an alternative to expansion of the electric grid.

5 For many years, with priority given to the building of generating plants, transmission and distribution systems have been neglected. The lack of upgrading of transmission and distribution networks has led to considerable power losses in the delivery process and to bottlenecks in transmission to locations where electricity demand is high. Also, provincial and regional transmission grids are rarely interconnected, leading to a limited interregional power trade. It is only since the late 1990s that more investment has been focused on the transmission and distribution systems.

Meeting the rapid growth of peak load demand is therefore an increasingly important task for China's power system. The flexibility of gas turbines for power generation (quick start and stop, short time needed to reach full load) makes it an excellent means of meeting the peak-load demand and improving grid reliability. However, meeting peak load alone may require the booking of a large part of the gas infrastructure, making it economically less attractive[6].

Need to reduce power-related environmental emissions

As discussed earlier, one of the policy priorities for China's power sector is to diversify away from the current coal-dominated supply structure. The prime reason for this diversification is not related to the supply security of coal, but to the reduction of power-related pollution, which is the largest air polluter in the country.

Three-quarters of power generation capacity in China is coal-fired. In the absence of appropriate control, coal-fired power generation produces massive sulphur dioxide (SO_2), nitrogen oxides (NOx) and releases dust and particulate matters. Table 4.5 shows the contribution of China's power sector to the total environmental emissions in the country.

Table 4.5

Environmental Emissions of China's Power Sector

	TSP*	SO_2**	NOx**	CO_2***
Emission Volume	4 Mt	7 Mt	n.a.	1226 Mt
% of National Total	28%	40%	80%	42%

* Total suspended particulate, 1994 data. *Source:* Battelle Memorial Institute, 1998.
** 1998 data. *Source:* Development Research Centre of the State Council, 2000. "Strategic Study on the Reform of China's Power System and Sustainable Development", Department of Industrial Economics, Beijing.
*** 1999 data. *Source:* IEA, 2001. *CO_2 Emissions from Fuel Combustion: 1971-1999.*

Sulphur dioxide pollution causes very frequent acid rains, which now affect 40% of the country. Confronted with the seriousness of environmental pollution, the Chinese government has had to take drastic measures to reduce it. In 1998, the government mapped out an "Acid Rain Control Area" and a "SO_2 Control Area" and started to implement strict controls on energy production and consumption activities in these two areas (see Annex I). The control measures that have direct impact on power plants include the following:

6 It makes a big difference, however, whether gas is used to cover daily and weekly peaks, which are due to social patterns, or to meet seasonal peaks. Daily and weekly peaks repeat themselves at short intervals, so gas supply could eventually be met with the pipeline buffer. However, peaks that go with the season, like winter peaks, require costly storage or high pipeline capacity reservation.

- Except for heat-based co-generation plants, a ban on building any coal-fired power plant in urban or suburban areas of middle and large cities;
- Any new or renovation power project using coal with a sulphur content above 1% must install desulphurisation equipment. Existing plants using coal with a sulphur content above 1% must take SO_2 reduction measures before 2000 and have to install flue-gas desulphurisation (FGD) equipment before 2010 or take other SO_2 reduction measures with the same effect.

Taking advantage of the relatively eased power supply situation in the second half of 1990s, the government also took a series of administrative measures to shut down a large number of small coal-fired power plants (50WM or below) which were judged inefficient and polluting[7].

Most coastal cities are under the acid rain control area and now prohibit the installation of new coal-fired power plants inside or close to densely populated areas. The ban on coal-fired plants in those areas certainly makes gas-fired generation one of the few acceptable alternatives from the environmental point of view.

Projections of gas-fired power generation

Given the generic advantages of gas-fired power generation and the specific Chinese conditions described above, gas-fired power generation holds significant potential.

According to the Energy Research Institute of the SDPC (Han & Liu, 1999), if 25% of the annual increase in thermal power generation between 1997 and 2010 is provided by natural gas, China will need to use 35 bcm/year of gas for power generation by 2010. If 40% of the annual increase in thermal power generation between 2010 and 2020 is provided by natural gas, then 81.2 bcm/year of natural gas will be needed for power generation by 2020.

Table 4.6

Projection of Natural Gas Demand for Power Generation

	Total Power demand (TWh)	Increase in power demand (TWh)	Increase in thermal power demand (TWh)	Share of gas in the increase in thermal power demand(%)	Total gas-fired power (TWh)	Natural gas demand (bcm)
2010	2,221.2	1,113.8*	757.8	25	189.5	35
2020	3,450.0	1,228.8**	1,097.5	40	439.0	81.2

* compared to the level of 1997; ** compared to the level of 2010.
Source: Han & Liu, 1999.

7 China has been closing small coal-fired units since 1997 as part of its campaign against the 'Five-smalls" which are inefficient and polluting small-scale factories. By the end of 2000, the government claimed to have shut down a total capacity of 10 GW of power generating capacity. However, by end 1999, small units below 50 MW still accounted for 15% of the total installed capacity. The 10th Five-Year Plan stipulates that this campaign of closing small units will continue.

Overall, these projections are very optimistic, as they give power generation, which only accounted for 2.8% of total gas demand in mainland China in 1997, a dominant role, accounting for 36% and 40% of total gas demand in 2010 and 2020 respectively. Gas would meet respectively 7% and 10% of the total electricity needs of the country in 2010 and 2020.

The State Power Corporation of China (SPCC) has laid out tentative plans for gas-fired generation up to 2010, as shown in Table 4.7. To absorb the gas from the West-East pipeline, the SPCC has planned 5.4 GW of gas-fired generating capacity in Henan province and east China. Other power generation projects are also planned for the Zhongxian-Wuhan pipeline, the Sebei-Lanzhou pipeline and Guangdong's LNG.

Table 4.7

State Power Corporation's Plans for Natural Gas-Fired Power Generation

	2001-2005	2006-2010
New capacity for construction	8,814 MW	22,371 MW
Capacity to be commissioned	4,884 MW	15,501 MW

Source: State Power Corporation, Communication to IEA, November 2001.

According to the SPCC, 12.5 bcm/y of gas will be used in power generation by 2005. Most of it will be consumed in the Yangtse River Delta (east China) and the Pearl River Delta (south China). Table 4.8 provides a regional breakdown of gas-fired capacity additions in 2005 and 2010.

Table 4.8

Regional Distribution of Gas-fired Power Generation Potential

	Total power capacity in China (GW)	Gas-fired capacity (GW)	South China	East China	North China	Others
2005	403	8.6	3	3.8	1	0.8
2010	514	20.1	7	8.1	3	2

Source: SDPC.

While gas-fired generation will essentially replace coal, it is interesting to note that the Chinese demand for coal will not decrease in volume. Indeed, even in the optimistic case where gas will account for 10% of the total power generating capacity in China by 2020 and assuming that all gas-fired generation will replace coal, Chinese coal demand for power generation will be still more than double the 2000 level.

CRITICAL ISSUES FOR DEVELOPING GAS-FIRED POWER GENERATION

China's potential for gas-fired generation is very significant, but realising this potential remains a daunting challenge, not least in meeting the target for the next five years. Critical issues affecting gas-fired generation are analysed below.

Cost competitiveness

The most important issue for developing gas-fired power generation is its competitiveness against alternative fuels, in particular coal. Even when the use of coal for power generation is excluded in urban areas and controlled in other areas, coal could still be widely used to generate power to feed the transmission network (coal-by-wire), in locations that are not restricted. The competitiveness of gas-fired generation therefore depends on the delivered prices of natural gas and alternative fuels to power plants, and capital and operating costs. Table 4.9 shows the prices of coal and gas in Beijing, Shanghai and Guangdong in 2000.

Table 4.9

Coal and Gas Prices in China in 2000

	Beijing	Shanghai	Shenzhen/Guangdong	National Average
Coal Price* (RMB/ton)	250	280	300	230
Gas Price** (RMB/cm)	1.1	1.35	n.a.	

Note: * Coal prices in each of these cities can vary significantly, depending on its quality and origin. The type of coal quoted here is steam coal with 1% of sulphur content and a heat value of 5,200 kcal/kg (with high ash content).
** Gas price is the current city-gate price in Beijing and the announced city-gate price in Shanghai. The heat value of gas is assumed to be 9,000 kcal/cubic meter.
Source: China Energy Research Society.

In order to provide a more quantitative picture of the competitiveness of gas-fired power generation, a spreadsheet model was developed to compare the levelised costs at busbar from a coal-fired power plant and a CCGT, both for base-load. Base-load is chosen because of the need for large-scale CCGT plants to act as an anchor to large pipeline or LNG projects. Key assumptions are provided in Table 4.10 and the method of calculation in Box 4.2. It should be made clear that this exercise is only illustrative and that real economic calculations must be done on the basis of the detailed data of any specific project.

Table 4.10

Key Assumptions for Cost Comparison between Coal and Gas-fired Plants in China

Parameters	Coal plant (Subcritical pulverised 2x300 MW)	Gas plant (CCGT 2x300 MW)
Capacity factor (%)	85	85
Economic life (years)	20	20
Capital cost (US$/kW)*	650 without FGD and 850 with FGD	500
O&M cost (US$/kWh)	0.005 without FGD and 0.007 with FGD	0.003
Efficiency (%)	35 without FGD and 34 with FGD	50
Fuel heat value	5,200 kcal/kg	9,000 kcal/cm
Construction time (years)	3	2
De-polluting equipment	• Equipped with high efficiency electrostatic precipitator to remove TSP; • FGD, which can remove 92% of SO_2, is not required for the moment by regulation since the sulphur content of coal is 1%.	
Other assumptions	Discount rate: 10% Exchange rate: 1US$=8.3RMB	

* Chinese sources hint at even lower specific capital costs for coal-fired power. The capital cost for a CCGT used here reflects the present cost reported for newly ordered CCGTs in the United States. Higher costs are reported in several other OECD countries and in most non-OECD countries.

Box 4.2

Methodology for an Economic Analysis of Gas-fired Power Generation in China

The present study is interested in establishing the relative competitiveness of gas and coal in power generation in China. To do that, some simple calculations are carried out using the spread sheet model, which combines the features of the IEA's Power Generation Model used for its biennial *World Energy Outlook* exercise and the model developed by the Pacific Northwest National Laboratory of the United States. The IEA uses the assumptions that are provided in Table 4.10.

The approach chosen is to calculate the levelised cost of power generation at busbar level for a pulverised coal-fired plant, with and without environmental externalities, and for a gas-fired combined cycle plant. This approach is based on the assumption that gas and coal-fired power plants will have to compete with each other to sell electricity at the lowest busbar cost.

The simulation is carried out for coal- and gas-fired power plants to produce one kWh of electricity at the same cost. For this, the following equation is used to determine the point at which the levelised busbar cost of gas-fired plants equals that of coal-fired plants ($/kWh):

(Annualised capital cost + Fuel price + O&M cost + Environmental fees)gas = (Annualised capital cost + Fuel price + O&M cost + Environmental fees)coal

Where Annualised capital cost = capacity recovery factor * capital cost / (load factor*8760)

In which,
capacity recovery factor = discount rate * (1+ discount rate)^N / ((1+ discount rate) ^{N} -1)
where N stands for the economic life of the power plant in number of years.

For a given price of gas, the price of coal is:

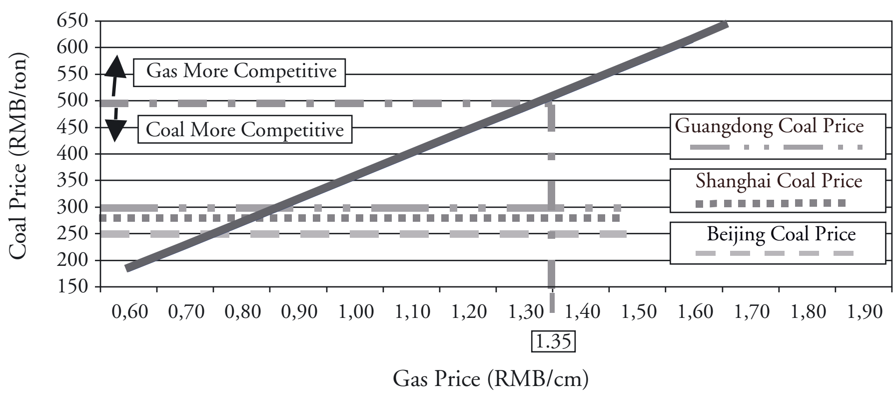
(Fuel price)coal = (Annualised capital cost + Fuel price + O&M cost + Environmental fees)gas – (Annualised capital cost + O&M price + Environmental fees)coal

With the above equation, one can obtain a range of coal prices that correspond to the range of gas prices to plot the line on which coal and gas will produce electricity with the same total levelised cost at the busbar.

Figure 4.4 shows the relative competitiveness of gas and coal for power generation. The diagonal line indicates where the gas prices in the horizontal axis would produce the same levelised cost of electricity from a typical CCGT plant with that of a simple coal-fired plant (without FGD) with coal prices in the vertical axis. It can be seen that for a steam coal price of 280 RMB/ton in Shanghai, the price of natural gas at the plant level would have to be lower than 0.85 RMB/cm to be competitive. For a coal price at 300 RMB/ton in Guangdong, the gas price needs to be lower than 0.90 RMB/cm to be competitive. As current gas prices at the plant gate are all above this range in both Beijing and Shanghai and are likely to be so in Guangdong, gas is not cost-competitive against coal for power generation, unless other benefits, currently not accounted for in economic calculations, are included.

Figure 4.4

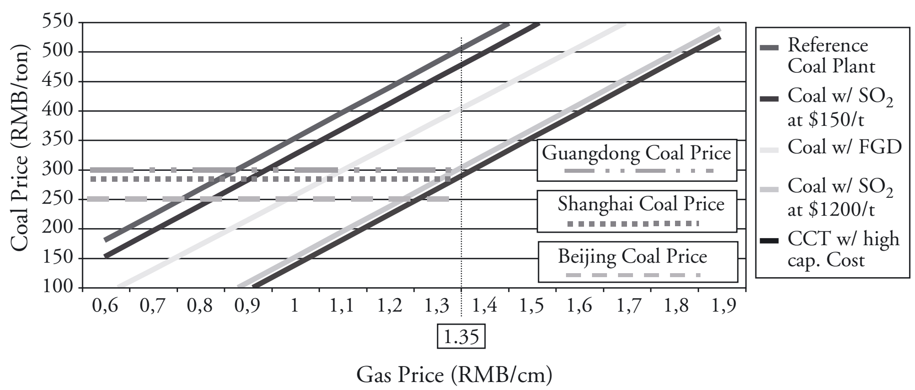
Relative Competitiveness of Gas and Coal for Power Generation in China



One way of improving the competitiveness of gas against coal is for the government to reflect the environmental effects of coal-fired plants into their costs. This could be done through a requirement on coal plants to install flue gas desulphurisation equipment, which would eliminate the majority of their SO_2 emissions, regardless of the sulphur content of the coal used. Another way is to impose charges for certain types of emissions such as SO_2 and NOx.

Figure 4.5

Impact of Environmental Measures on the Competitiveness of Gas against Coal in Power Generation



The simulation shows that the mandatory installation of FGD could significantly improve the competitiveness of gas against coal. It could make gas competitive with coal in Beijing at a gas price of 1.0 RMB/cm, and in Shanghai at 1.08 RMB/cm.

Without the mandatory installation of FGD, the imposition of an environmental cost of 1,200 RMB/ton (equivalent to US$150/ton) of SO_2, which is currently applied to power plants in Beijing, would not significantly affect the relative competitiveness of gas *versus* coal. For gas to compete with coal at a gas price of 1.35 RMB/cm, there must be a SO_2 emission fee of at least US$1200/ton in Shanghai (and a bit higher in Beijing), which is unlikely to be acceptable.

If the capital cost of coal-fired plants is increased to US$1,350/kW, which is equivalent to the cost of a coal-fired PFBC (pressurised fluidised bed combustion) plant or the lowest end of an Integrated Gasification and Combined Cycle (IGCC) plant, a gas price of 1.35 RMB/cm would yield a generation cost equal to that of coal at a price of 280 RMB/ton. This means that gas-fired plants can be competitive against coal plants with advanced clean coal technologies (CCT).

Figure 4.5 illustrates the results of the impact assessment on generating costs for new plant of:

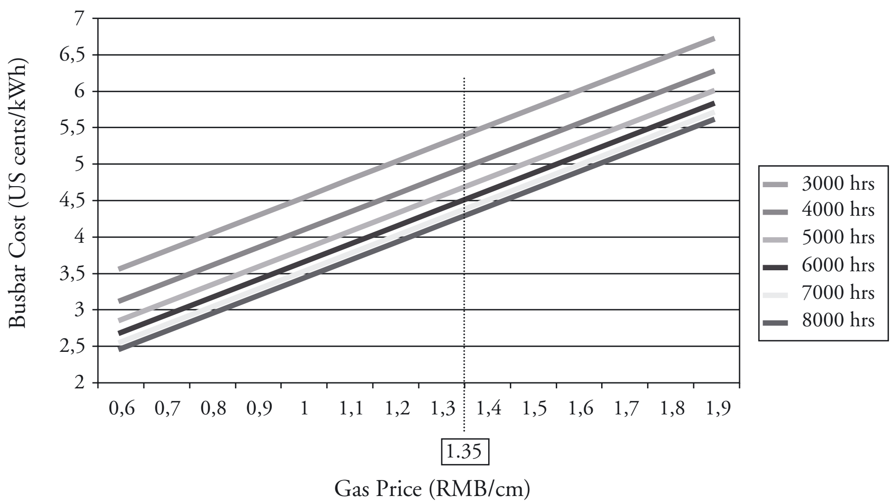
1) an SO_2 emission fee of US$150/ton;
2) the installation of FGD in the coal-fired power plant;
3) an SO_2 emission fee of US$1200/ton; and
4) a CCT plant with capital cost at US$1,350/kW.

Other ways to improve the commercial viability of gas-fired generation are analysed in the next section of this chapter

The above analysis is based on the assumption that gas is used for base-load generation, with a load factor of 85% (7,450 hours/year). The generation cost will be much higher, however, if the gas-fired plant is to be used only for peak load with a much lower load factor. Figure 4.6 shows the economics of gas-fired generation according to gas price and the load factor of the plant.

Figure 4.6

Impact of Load Factor on Economics of Gas-fired Power Generation



The simulation carried out in this study is a simplified way of comparing the relative economics of gas and coal for power generation based on the levelised cost at the busbar. Such a comparison has many limits, which must be clearly noted to avoid any misuse of the results. In particular, it did not take into account the following factors, which play in favour of gas-fired generation:

- The costs beyond the busbar, that is, those related to the transmission and distribution systems and the losses incurred. Transmission and distribution costs could account, on average, for 30% of the total electricity cost, and the T&D energy losses in China amount to 7.7%. As coal-fired generation is forbidden in urban areas, one needs to add these costs to the busbar cost of coal-fired plants, while such costs for gas-fired plants are much lower as they can be located in urban load centres. This could make gas more competitive.
- The costs of other pollutants such as NOx and fine particulates that are not removed by the electrical precipitator of a coal plant.
- The differences between capacity-planning decisions and plant dispatch decisions. While capacity-planning decisions can be made mainly on the basis of the relative economics of different options, the dispatch priority will need to be based on the generation cost, but also take into account the contractual constraints (take-or-pay contract, power purchase agreements).

- The regional differences in existing capacity make-up/grid constraints/generation costs and impact on end-user price. In each region of China, there are practical limitations of quick displacement/replacement of existing large based-load coal-fired plants, given electricity growth projection, existing plant age, and capacity.
- System technical requirements for reliability and stability such as the need to provide reactive power at the load centre and reliability improvements when the plant is near the load.
- Other objectives of power market reform and the balance between these objectives with regard to environmental protection, energy security/reliability and social benefits that may affect planning decisions.

The real calculation for commercial projects is much more complex, as cost items have to be divided into several sub-items (e.g. fixed and variable O&M costs) and take into account other cost items (e.g. rate of return, capital depreciation, insurance, etc.). The model nevertheless illustrates very well the competitiveness of gas *vis-à-vis* coal for power generation in China.

The model calculations show that the assumed lower capital costs and higher efficiency of CCGTs *verus* coal-fired power plants do not make up for the advantage of low-cost coal over gas, unless the environmental impact of coal is valued at a high rate. It may be worthwhile to discuss whether the investment cost for gas-fired power would be cheaper in China than coal-fired power capacity. The background is that coal-fired power plants (up to 300 MW and more) can be manufactured in China, whereas a CCGT plant has to be imported, and the costs of imported equipment are likely to be higher than those in OECD countries.

As noted earlier, the comparison is made on the basis of base-load generation, which leads to the conclusion that gas is not competitive against coal. However, gas could be competitive for peak-load or mid-merit load, assuming lower-cost gas-based capacity as compared to coal-fired power capacity. An advantage for peak-load gas generation would still depend very much on the prices at which the generated power is sold.

Peak versus base-load contradiction

As shown in Table 4.8, the greatest potential for gas-fired power generation is in three Chinese regions: east China including Shanghai, south China including Guangdong, and north China including Beijing. These regions badly need generation capacity with strong peak shaving abilities. But the need to provide anchors for large gas projects, such as WEP and LNG imports, means that the planned gas-fired generation projects will have to be operated for base-load supplies to ensure that the gas supply infrastructure is fully utilised.

If gas-fired plants are to operate in base load, there will be inherent competition in each of these regions between the envisaged gas-fired power projects with other base-load supply expansion projects:

- For north China, gas-fired power generation will be in competition with electricity from the northern corridor of the “West-east power transmission project”, where coal-mine-mouth power will be transported from Shanxi, Shaanxi and the west of Inner Mongolia, and hydropower from upstream on the Yellow River.

- For east China, competition with nuclear power projects in Zhejiang and Jiangsu provinces, and with hydropower from the Three Gorges project.
- For south China, including Guangdong, competition will be with nuclear power that is under construction and with power from the southern corridor of the West-East power transmission project.

The large potential for future growth in electricity demand may provide room to accommodate additional gas-fired base-load generation, but this competition will raise questions on the wholesale price to be paid to the gas-fired base-load units.

Power sector reform: opportunities and uncertainties

China's power sector has undergone a number of stages of reform over the last two decades and has just started a new phase of structural change (Box 4.3). The new reform process is designed to achieve the following objectives:

- to improve power sector efficiency and service quality;
- to introduce competition; and
- to rationalise the industry, lower costs, and reduce electricity prices.

Box 4.3

Power Sector Reform in China

China started the reform of its power sector in the early 1980s, in line with the country's overall economic reform and market opening process. Early reform consisted of decentralisation of government functions, encouragement of multi-channel financing for power-plant building, greater commercial orientation, permission and incentives for private and foreign investors, and the development of a legal framework, with the promulgation of the Electricity Law in 1995. China was the host of the world's first Build-Own-Transfer (BOT) private power project (Shajiao B by Hopewell Holding), which was completed in 1987 in Guangdong. One significant step in the reform process was the creation of the State Power Corporation of China (SPCC) in 1997 by the then Ministry of Electrical Power. When the ministry was abolished in 1998 as part of central government reform, the SPCC became the sole operator to manage state assets in power generation. Today, SPCC owns 50% of China's total generating assets and, except for a few provinces such as Guangdong, Tibet and Inner Mongolia, controls all the power grids in the country.

Despite the success of China's power industry in rapidly raising its power generation capacity to overcome power supply shortages, which had been serious in the 1980s and early 90s, the current structure poses significant problems. The management system, which is still based on the model of the central planning period, limits rational and efficient utilisation of resources and becomes inadequate for the sector's further development. The vertically integrated state-owned monopoly, with its cost-plus electricity pricing approach, does not provide the incentives needed to improve efficiency in order to lower costs and develop markets. It also hinders the introduction of competition and the development of new and clean sources of power generation. A new reform, focusing on structural changes, is therefore needed.

The first step of the process involves separating generation and transmission, introducing competitive bidding among generators, and establishing a modern regulatory structure. Starting in 1998, pilot programmes of "separation of generation from transmission with competitive bidding by generators to sell power" have been carried out in some provinces. If successful, this model would be applied nationwide. However, a joint evaluation conducted by the SDPC and the SETC in 2000 concluded that these pilot programmes have not produced satisfactory results or provided any successful experience for promotion in other provinces. Lack of ownership separation was considered one of the key reasons for the failure, as provincial power companies which own transmission grids also have generation assets and therefore there was no fair competition with independent producers. This had led to a situation where a large hydropower plant (Er-Tan), built with a huge World Bank loan, was obliged to waste water as the local grid operator preferred to run with its own coal-fired power plants.

In February 2002, the government announced a plan, which was apparently approved by the Party's Politburo, that will restructure China's power industry in the following way:

- Separation of transmission from generation business;
- Creation of two grid companies with the Southern Power Grid Company, which will incorporate the grids of Guangdong, Yunnan, Guizhou, Hainan and Guangxi provinces in southern China; and the State Power Grid Company will take over the grids in the rest of the country.
- The State Power Grid Company will keep 20% of the total generation assets of the SPCC, which stands at 150 GW, for peak shaving purpose. The rest of the SPCC's generation assets will be distributed to four or five companies including: State Power Generation Company (with current generating capacity of 3.5 GW), Beijing Datang Generation Company (with 5.57GW of current capacity), Huaneng Power International (current capacity at 10.81 GW) and Guohua Power Generation Company (current capacity at 4.3 GW).
- Establishment of an Electrical Power Regulatory Commission under the State Council to regulate the power industry.

This process will certainly have a significant impact on the viability of gas-fired power generation. While it may provide further opportunities for gas-fired generation, it may also cast a number of uncertainties.

Given that gas-fired generation does not have the cost advantage over coal-fired plants, it may encounter significant difficulties in an environment of competitive bidding, where generators will inevitably choose the cheapest source of generation, unless there are other constraints. The problem would be even more acute if gas-fired generation had to compete with old coal-fired plants, which have already been amortised. Existing coal-fired plants will have a greater advantage if they are not required to clean up the pollution they cause.

For the moment, the reform seems to focus only on the separation of generation and transmission. It is not yet clear how the redistribution of SPCC's assets will be carried out; neither is it clear whether and when the distribution will be totally separated from transmission or whether direct sales to large consumers will be encouraged. Other important questions also remain, such as the precise role and functions of the regulatory commission. It is widely believed that this dissolution of the SPCC is just the first step of a major reform. It may take a few years to complete this stage before other steps can be taken to introduce larger scope competition. True competition requires a robust transmission grid, non-colluding suppliers, an independent regulatory body, and enforceable laws and national regulations. None of these elements are present yet in China. It will probably take quite a number of years to develop full-scale competition in the power sector. Meanwhile, the continuing uncertainty on the next reform steps may cause delays in power plant construction and grid expansion programmes.

Electricity pricing

Electricity pricing policies have a significant effect on the commercial viability of gas-fired generation. The current power-tariff system in China, both for wholesale generators and for the retail market, is irrational and undermines the competitiveness of gas. One of the key objectives of China's current power sector reform is to rationalise its tariff system.

The wholesale tariff for electricity is today based on a "cost-plus" approach: cost of generation (capital and fuel) plus reasonable profit. This tariff has to be approved by provincial price control bureaux and by the SDPC. This system creates different tariffs for different power generation projects and results in large disparities: a power plant can sell electricity at different tariffs depending on the construction phase or on the unit from which the electricity was generated.

Dispatch hours are determined according to an equitable plan rather than by first dispatching the lowest-cost power or power from clean generating plants. This removes any incentive for power plants to raise efficiency, reduce costs or improve environmental performance.

There is also a total lack of transparency in procedures for allocating the costs of generation, transmission and distribution. Without a clear breakdown of costs and prices, it is impossible to put in place incentives to reduce costs. On the retail side, in addition to generation, transmission and distribution charges, consumers are often subject to many supplementary charges imposed by local power supply bureaux or municipalities. Electricity prices can therefore be very different from one city to another.

In an effort to reduce peak demand, in 1995 the government decided to apply a time of day (TOD) tariff with the objective of reducing peak load (10-12 GW of capacity) by 10 to 15% within three to four years. Despite this ambitious target, however, this system has not been widely adopted. Except for Shanghai, where the tariff gap between peak load and base load appears to be reasonable[8], the gap is too small in other cities or provinces to be able to influence consumer behaviour. Furthermore, as the TOD tariff does not apply to in-grid purchase prices when generation is separated from transmission, distribution companies can only buy electricity based on the average rate and sell it at TOD tariffs. The more they sell at base-load, the less revenue they get from those sales, so naturally they want to sell maximum power at peak load. This does not encourage demand-side management from a utility point of view.

The establishment of a uniform and transparent pricing system in China's electricity sector will help investors to assess the potential benefits and risks of new gas-fired projects.

Environmental regulations and enforcement

Environmental protection, and in particular the reduction of local atmospheric pollution, is the key driving force for increased gas use in China. Power generation is the single largest air polluter. This is also one of the main reasons for developing gas-fired power generation in China. As demonstrated earlier, the cost effectiveness of gas-fired generation will be improved if the environmental costs of coal-fired generation are taken into account, either by requiring the use of advanced clean coal technologies or by imposing very high emission fees.

The critical issue here is the stringency and credibility of China's environmental regulations on air pollution. As shown in Annex I of the present report, China has put in place a set of legislative documents in recent years as part of its efforts to reduce environmental pollution. However, the whole system still suffers from a number of inadequacies that need to be addressed.

Table 4.11

Emission Standards (Limits) for Coal-Fired Power Plants in Selected Countries (microgram per cubic meter)

	China	Australia	Canada	Japan	EU
Particulate matter:		100	130	100	Plant≥500MW: 50
Urban areas:	200				Plant<500MW:100
Elsewhere:	500				
Old plants:	600				
SO_2:		200	700	223	400
Sulphur content of coal≤1%:	2100	Lignite fired: 400			
Sulphur content of coal≥1%:	1200	Hard coal: 200			
NOx (NO_2):		860	460	410	65
Liquid discharge:	1,000				
Solid discharge:	650				

Source: China Energy Research Society; *IEA Coal Information*, 2001 Edition.

8 For Shanghai, the tariff for industry and commercial sectors is divided into periods: peak (8h00-11h00 and 18h00-21h00), normal (6h00-8h00, 11h00-18h00 and 21h00-22h00) and valley (22h00-6h00). The tariff ratio is approximately 3:2:1 for the three periods. For the residential sector, a day is only divided into two periods: normal (6h00-22h00) and valley (22h00-6h00). The tariff ratio is 2:1. The TOD tariff is only partially applied to the residential sector as it requires special meters.

Lower emission standards

Standards or limits on the emission of air pollutants in China are much less stringent than those in OECD countries. Table 4.11 provides the standards for coal-fired power plants in China and compares them with those in a few selected countries.

Inadequacy of enforcement

While the central government, represented by the State Environmental Protection Administration (SEPA), oversees the implementation of environmental policies, laws and regulations, the enforcement of those laws and regulations is the responsibility of local environmental protection bureaux (EPBs). These bureaux monitor power plants' emissions in their respective areas and establish the amount of fees the plants have to pay, if any.

Local EPBs lack resources – they are under-funded, with limited and untrained staff – and as a result lack either the incentive or the means for unannounced inspections. Besides, they rely on municipal governments for funding, which creates a conflict of interest between EPBs – whose objective is to try to reduce pollution by imposing fees, fines or even closing down plants – and municipal governments – whose objective is to support local industries and increase tax revenues. Lack of inspection also means that those power plants which have installed FGD units in order to comply with regulations do not operate them, as operation costs are high (adding on average RMB0.01/kWh to the variable cost of generation).

Monitoring of power plant emissions is infrequent and reporting to local EPBs is poor. Lack of authority or juridical power leads to the non-respect of local EPBs and frequent violation of regulations: refusal to declare emissions or false statement of emissions, disabling of emission control facilities, restriction of plant access to EPB staff or simply refusal to pay the fees. The non-uniformity in applying regulations is a major problem: by law, emissions can only be levied on profitable enterprises. This leaves the unprofitable ones, which are often big polluters, with no incentive to reduce emissions. Also, the amount of fees payable by a company can be negotiated with the EPB.

Inadequacy of emission fees' system

China began a trial programme of SO_2 emission fees in 1993-94 in two provinces (Guangdong and Guizhou) and nine other cities[9], with a charge of RMB200/ton. From 1998, the programme has been extended to other parts of the country, to include all of the "Acid-rain control regions" and "SO_2 pollution control regions". The fee was increased to RMB800/ton in September 2000 and for Beijing, it was increased to RMB1200/ton in March 2000. In contrast to the usual pollution charge, which is levied only on the volume in excess of the permitted level, the SO_2 fee applies to the total volume of emissions. Reportedly, a few city governments have started a trial programme on SO_2 emission trading.

Despite these efforts, a number of problems remain on the SO_2 emission fee system:

9 They are Chongqing, Yibin, Nanning, Guilin, Liuzhou, Changsha, Hangzhou, Qingdao and Yichang.

- First, the fees do not adequately reflect the true environmental costs of pollution and are far below the cost of installing desulphurisation units. This has led to power plants preferring to pay the fees rather than investing in FGD units.
- A part of the fees is returned to the polluting plants as exemption of repayment of loans or as low-interest loans to invest in environmental protection technologies. This measure is contrary to the "polluter pays" principle.
- Regulations for older plants (both SO_2 and particulate) are plant-specific and depend on many characteristics, which make the emission fees' setting system extremely vague. This lenient treatment for older plants helps to keep highly polluting power plants running.
- Coal-fired power plants burning high-sulphur content (above 1%) coal are required to install FGD units, while those burning low-sulphur content coal are not. This creates an unfair imbalance in power generation costs and is unjustified, as globally, emissions from plants without environmental protection equipment will be higher than emissions from power plants equipped with FGD units.

These problems explain in large part why only 5 GW of China's coal-fired power plants are equipped with FGD systems today.

POLICIES AND MEASURES FOR INCREASING GAS USE IN POWER GENERATION

Given the problems analysed above, it is necessary to implement policies and measures to promote gas-fired power generation, at least during the initial period of gas market development, in order to trigger the necessary development to support gas infrastructure projects. Actions could be taken in the following areas.

Including pro-clean energy sources in the power-sector reform package

As the power-sector reform package is in the process of being elaborated, China today has an excellent opportunity to introduce measures that would encourage the development of clean power sources. It will be too late once the reformed structure has already been put in place. Given that the bulk of China's electricity supply will come from coal-fired plants and that gas-fired plants, clean coal technologies, and renewable energy sources face similar types of problems, there is a need to take an integrated approach to include all these sources of energy as clean sources. Measures such as the mandatory share in the generation mix of electricity from clean sources would help the development of gas-fired generation, together with renewables, combined heat and power (CHP) and clean coal technologies.

Improving commercial viability of gas-fired power generation

The simple calculations of this study show that at the current and future expected level of gas prices, gas-fired power generation will not be competitive compared to coal-fired power plants without FGD for base-load generation in many Chinese regions. The competitiveness of gas-fired plans *vis-à-vis* coal plants can be improved if all coal plants are required to install and effectively operate FGD equipment regardless of the sulphur content of coal, but the mandatory installation of FGD does not appear to be sufficient. An alternative way is to impose high emissions fees on SO_2 and other pollutants. However, the imposition of high emissions fees, something around US$1200/ton of SO_2, is unlikely to be feasible.

In areas where medium or large-scale CCGT units are desirable to accelerate gas market development by anchoring gas demand, the government could consider the following supportive measures:

- *Special PPA*: Allow and encourage individual project developers to seek a special class of power purchase agreement (PPA) with power transmission companies (such as "take-or-pay" for a minimum amount of power per year) and secure the execution of those agreements. Guaranteeing these agreements will be very important during the transition period of power sector reform, which has just started.
- *Direct connection to pipelines*: Allow large gas-fired plants to negotiate gas prices with the transmission pipeline companies and source their supplies directly from the gas trunk line, without the obligation of passing through the local distribution companies. This could avoid 0.2-0.3 RMB/cm of distribution cost. Care should be taken to ensure the consistency between this permission and the need for market franchise by the distribution companies. There should also be some care taken to avoid a too high capacity charge for gas demand by the gas-fired plant.
- *TOD wholesale prices*: For those gas turbine plants used for peak-shaving, power pricing should reflect the true market value of electricity at different times of the day. A time-of-day (TOD) tariff should be applied to wholesale purchases of electricity so that those peak-shaving plants can get the peak-load tariff. Currently, the pricing formula is based on the average wholesale price, which is over-weighted by coal, and there is no law requiring utility companies to pay peaking power price.
- *Environmental enforcement*: Strengthen the enforcement of environmental regulations (see below) so that dirty and inefficient coal plants will not be favoured.
- *Tax incentives:* Tax breaks should be offered on CCGT technologies not yet produced in China and on the installation of CCGT plants to reduce the investment cost of these plants. The development of domestic manufacturing capacity for gas turbines would also reduce the total investment and operation/maintenance cost in gas-fired generation.

Strengthening the incorporation of environmental externalities

It will be difficult for gas-fired generation to be on a level playing field if the environmental consequences or true costs and benefits of various fuels and technologies are not appropriately taken into consideration. To create such a level playing field, emission standards will need to be tightened and actively enforced. It is encouraging to note that China has stated its objective of implementing European air standards by 2005. This calls for greater efforts in the enforcement of regulations.

To start with, the price/penalty per ton of emission (SO_2, NOx, particulate) should fully reflect the market value of emission permits and take into consideration the health damage to the public. It involves the following key areas of action:

- SO_2 emission charge should be increased from the current level;
- Each power company and each unit of a power plant should have an upper limit of SO_2 emission per year;
- Fees should be applied to both profitable and unprofitable companies;
- Fees should be set according to the severity of pollution;
- Fees should be extended to other pollutants (TSP, NOx and untreated waste water);
- They should be indexed to inflation and should increase with time to remain a real incentive to reduce pollution.
- Fees should be independent of the fuel source: they should be imposed equally on power plants using low-sulphur coal or high-sulphur coal. All emissions regulations that are based on coal quality should be revised.
- Links must be severed between fees collected by local environmental protection bureaux and the use of these fees. Fees should be transferred directly to the General tax fund and should not be used either to fund EPBs or as loans to polluting plants.
- Based on the experiences gained from the trial phase, SO_2 emission trading should be formally established.

A critical point on environmental enforcement is the independence and authority of local EPBs. Acting not only as watchdogs, these EPBs are essential to the effective enforcement of environmental regulations. EPBs should be sufficiently funded directly by the central government to reduce the influence from local governments. They should be appropriately empowered or directly linked to legal authorities such as local courts or tribunals.

Enforcement of existing environmental regulations on emission control (SOx, NOx and particulates) should be tightened so that coal plants are not favoured. Coal plants (especially new ones) should all be required to have FGD equipment and to use it, and the emissions from those plants constantly monitored through automatic systems. If a FGD unit is installed in a coal-fired power plant then costs should be allowed to be part of the revenue requirement. Today, FGDs are funded by foreign aid and concessional loans. FGD costs should be included in coal-fired electricity prices so that natural-gas-fired power can compete fairly.

Although China does not have any CO_2 reduction commitment under the Kyoto Protocol, the imposition of any carbon value, that is, the value for not emitting CO_2, would also improve the competitiveness of gas-fired generation against coal.

In extending the use of economic instruments for environmental protection, China should continue to use command and control administrative measures in relation to coal-fired power plants. China should also consider banning, or extending the current ban, on any type of coal plant in the Yangtze River Delta area and Pearl River Delta, and in all major cities with a population of over 1 million.

Building small and medium-scale gas-fired units close to demand centres

In areas where large-scale CCGT is not competitive, serious consideration should be given to small and medium-sized gas-fired units in the range of 10-50 MW. These units are almost as efficient as large ones and their capital cost per kW is not significantly higher than that of large CCGTs. They have an additional advantage in that a much higher percentage of their waste heat can find useful applications, which can significantly improve their economics. In the case of their decentralised deployment close to demand centres, they can save the costs that would have been necessary for the expansion of the electric grid. Installed in large numbers they can easily make up the total capacity of a large unit and can also facilitate the development of a local gas distribution system. Where possible, waste heat should be used in the form of combined heat and power production.

Given that the government has closed down many small coal-fired power plants (less than 50MW) and has announced its intention to continue this campaign in the coming years, the new gas-fired units could easily fit in without changing the configuration of the electric grid. They could possibly also take up the existing contractual power delivery pattern for peak and upper-middle loads. The installation of gas-fired power plants should be concentrated in regions where gas has additional advantages over coal-fired power, for example areas with high coal freight.

In view of the potentially large market for gas turbines (and CCGTs), China might consider acquiring the capacity to build gas turbines domestically.

Developing distributed gas-fired generation, co-generation and poly-generation

An interesting option for increased gas-fired generation would be the development of distributed generation[10] either in the form of combined heat and power (CHP) or co-generation or tri-generation of combined cooling, heating and power (CCHP). Distributed generation by decentralised units has been described as a revolutionary technology that could fundamentally alter the organisation of the electricity supply industry. It is already attracting increasing interest in OECD countries (Box 4.4). These decentralised units are usually small, ranging from a few kW to a few MW of capacity and run by gas engine (50-5,000 kW), gas turbine (1-20 MW) or micro-turbine (30-200 kW). They are modular, so can be easily combined to reach the required size. Their cleanliness and small space requirement allow their installation in densely populated urban areas. Other advantages of these distributed generation facilities include their high efficiency (80-90% for advanced CCHP), high reliability compared to grid supply which is vulnerable to weather and other incidents, and savings in transmission and distribution costs and losses.

10 Distributed generation is defined as a generating plant serving a customer on-site, or providing support to a distribution network, and connected to the grid at distribution level voltages.

Box 4.4

Distributed Generation in OECD Countries

In OECD countries, distributed generation, especially by small plants fired with natural gas, is attracting increasing interest and policy attention and is expected to play a greater role in power generation in the future. Major factors behind this increasing interest include electricity market liberalisation; developments in distributed generation technology; constraints on the construction of new transmission lines; increased customer demand for highly reliable electricity, opportunities to meet one's own heating and cooling needs while being able to sell surplus electricity, and concerns about climate change.

Combined heat and power (CHP) is a well established application of distributed generation. It is regarded as one of the very few technologies that can offer a significant short- or medium-term contribution to energy efficiency improvement and environmental protection on satisfactory economic terms.

In the European Union, CHP accounted for 72 GW of capacity and 11% of the total electricity generated in 1998, although the fraction varies greatly from 1.9% (Ireland) to 62.3% (Denmark). In a 1997 communication, the European Commission proposed a community strategy to promote CHP to increase energy efficiency and reduce greenhouse gas emissions. It proposed that a doubling of the 1994 level of CHP from 9% to 18% was "realistically achievable" but requires Member states to remove various obstacles to CHP. In the United States, CHP accounts for 50 GW, or about 6% of the country's total power generating capacity. Industrial applications account for about 90% of the total CHP capacity. The US Department of Energy (DOE) estimated an additional 160 GW of CHP potential in the US, of which 88 GW is in the industrial sector and the rest in the commercial sector. In 1998, the DOE and the US Environmental Protection Agency jointly developed a "National CHP Roadmap" intended to double the CHP capacity from 46 GW in 1998 to 93 GW by 2010. In Japan, CHP capacity is around 5.5 GW, of which 4.4 GW is industrial and 1.1 GW is commercial. Growth in CHP has been steady, at a rate of over 360 MW per year since the late 1980s. In Korea, public CHP plants account for 15% of gas consumption in the country.

The growth of CHP in OECD countries is largely due to favourable government and regulatory policies. These policies have taken the form of national targets for electricity from CHP encouraged by investment tax credits, obligations on the electric utility to purchase the power produced, favourable prices for fuel or for ancillary services provided to the CHP scheme, and favourable electricity prices, in some cases supported by government subsidies.

Nevertheless, there remain substantial institutional and regulatory barriers to fully develop distributed generation or CHP markets:

- In many OECD jurisdictions, partially liberalised markets leave distributed generation competing with the utility due to the lack of legal access to the distribution grid.

- The lack of standards for connection of smaller distributed generation increases transaction costs for distributor and distributed generator.
- The variation in capabilities of distribution companies and the lack of incentives for distributors to encourage distributed generation and to export power to the grid when this may reduce system costs.
- Emissions regulations that can be overly demanding for small sources.

Source: IEA, 2002. *Distributed Generation in Liberalised Electricity Markets.*

CHP in China

In China, the development of distributed generation has just started with the government's encouragement to develop gas-fired CHP. In August 2000, a set of regulations was jointly published by the SDPC, SETC, SEPA and the Ministry of Construction. These regulations recognised the benefits of CHP (energy saving, environmental protection, improvement of heat supply quality and increased power supply), made the promotion of CHP and CCHP development a state policy, and required authorities at different levels to give full support[11]. Key provisions (Articles 14-17) of the joint regulations include:

- (The state) encourages the development of gas-fired-steam combined cycle heat and power co-operation on a reasonable scale, in particular those using natural gas and coal-bed methane;
- Reasonable gas prices should be given to gas-fired CHP plants as a recognition of their stability in gas use and ability for peak shaving in power demand;
- (The state) promotes the development of small-scale gas-fired CHP plants in dispersed public buildings such as factories, office buildings, hotels, commercial complexes, hospitals and schools in regions where conditions for such development exist;
- Conversion of heating boilers with unit capacity of 20 ton/hour and operational time of 4000 hours per year into CHP plants, when the economics of such conversion can be justified;
- Ban on the construction of any coal-fired CHP plant or heating boiler in areas where centralised heating is provided by existing or planned co-generation plants;
- Demolition of small heating boilers within three months after the commissioning of CHP plants;
- Ban on the operation of any dispersed coal-fired heating boilers in areas deserved by CHP plants;
- Urban residential areas are required to use centralised district heating to replace the dispersed heating by small boilers;

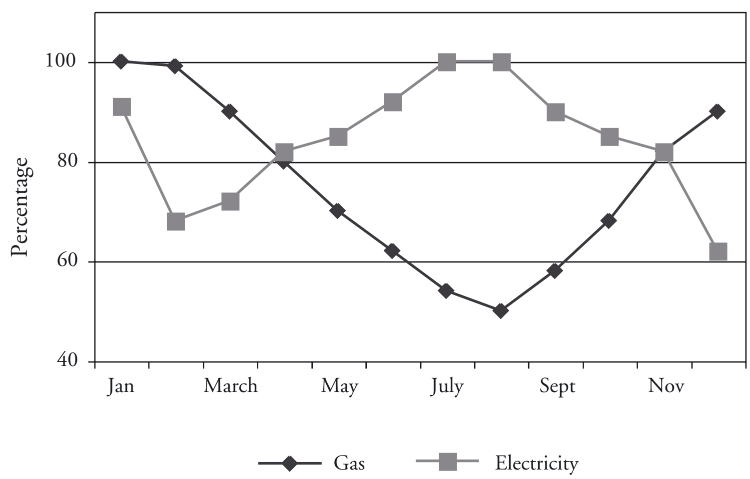
11 The impact of these measures still remains to be seen. One particular problem is that CHP is more relevant in China's industrial sector where the balance between heat load and power load, which is critical for a CHP project, is easier to control. But these regulations tend to focus on urban residential and commercial areas.

- Local municipal governments are required to provide a certain level of funding to support the development of CHP and centralised heating projects.

The development of gas-fired co-generation or tri-generation makes important economic sense in large consuming markets such as Beijing, Shanghai and Guangdong. These cities face an important problem in meeting peak-load demand, due mainly to the increased use of air-conditioners in offices and households during the summer. At the same time, gas demand is lowest in summer and highest in winter[12]. Figure 4.7 illustrates the complementarity of gas and electricity demand in Shanghai, which argues for encouraging gas use in summer.

Figure 4.7

Yearly Load Pattern of Gas and Electricity Demand in Shanghai, 1998



Source: Tongji University.

There is thus a strong need to develop gas-consuming activities during the low gas demand summer period. The development of a gas-fired air-conditioning system, or the CCHP system, would reduce the peak electricity demand and increase gas consumption – a win-win situation for both electricity and gas.

However, the development of these distributed systems will take time. The government needs to take serious actions to overcome some of the significant barriers for their development. In particular, it has to remove the difficulties for small units to get connected to the grid, so they can sell surplus power and secure back-up supply. Developing standardised interconnection rules for these small generators is also an urgent task.

12 The ratio between peak and bottom demand was 6 in the case of Beijing in 2000.

CONCLUSIONS AND RECOMMENDATIONS

Gas-fired generation, just like China's gas industry, is in the early stages of infancy. Overall, there seems to be a need to develop gas-fired power projects, perhaps for an initial period of 5-10 years, to accelerate the development of a gas market, and to support the economics of large gas infrastructure projects such as the West-East Pipeline or the LNG terminal. At present prices, however, gas-fired base-load generation cannot compete with the coal-fired equivalent in most Chinese regions, if the true costs (including environmental) of delivering electricity from these two options are not appropriately taken into account.

Clearly, it will be difficult to find the premium of gas for power generation that is usually available in many OECD countries, given the much smaller difference in investment costs between gas-fired and coal-fired power generation in China. The premium for gas-fired power in China is mainly in small and medium-scale gas-fired generation that replaces coal or heavy fuel oil for peak-shaving purposes. But peak-shaving alone would not be sufficient to absorb large quantities of gas. In some areas, it may be justified to opt for medium-size CCGT plants, provided that appropriate arrangements are made to make them commercially viable.

There are important advantages, however, to installing smaller units of gas-fired power in the range 10-50 MW as they can be deployed in a decentralised way. The current campaign of closing down small coal-fired generators provides a good opportunity for the development of such a system, and the total capacity closed down which will have to be replaced is substantial.

The real premium market for gas-fired power is in distributed generation units in urban areas to provide heat, cooling and power. But their development takes time and also involves a whole set of issues that need to be addressed, namely the possibility of feeding surplus electricity and receiving back-up power from the grid at reasonable prices.

If gas for power generation is to be developed in China, the government also needs to take a number of other actions. They include the introduction and enforcement of tighter environmental regulations, electricity pricing reforms and fiscal measures. Reform of the power sector may provide opportunities for gas-fired generation, but the government should try to minimise the uncertainties it may cause for gas-fired power as well as other power-sector projects.

Based on the analyses of this chapter, the following recommendations are formulated:

RECOMMENDATIONS ON GAS FOR POWER GENERATION

The Chinese government should:

- Where conditions permit, seek ways of promoting base-load gas-fired power generation plants to support the expedient development of a gas market and to anchor large-scale gas infrastructure development.
- Encourage the development of decentralised gas-fired generation by a large number of relatively small and medium-sized gas turbines, and where possible as heat and power co-generation or heat, cooling and power tri-generation projects, and pursue this as a medium and long-term strategic orientation;
- Rationalise electricity pricing schemes to ensure that tariffs at wholesale levels better reflect the cost of peaking and mid-merit generation;
- Take the historical opportunity of the electricity market reform to include pro-clean energy sources in the current power-sector reform package; and make a clear policy pronouncement that sets the government's long-term vision for the power sector in order to reduce uncertainties;
- Tighten environmental regulations on coal-fired power plants and strengthen their enforcement, as detailed in this chapter;
- Exploit the potential of the summer-winter complementarity in gas and electricity demand by promoting gas-fired air-conditioning systems and peak-load generation.
- Develop the domestic capacity to manufacture, build and operate small and medium-sized gas turbines and CCGTs in China.

ISSUES OF LOCAL GAS DISTRIBUTION

Highlights:

- *Local gas distribution companies in China, which have been accustomed to distributing manufactured gas, now face important challenges in managing the distribution of natural gas. They need to overcome a big cultural gap between the management of scarcity in the case of manufactured gas, and the management of abundance brought about by large-scale natural gas projects. They need to actively develop a marketing and sales policy, and improve relations with customers to provide a full range of services.*
- *Gas conversion is a major area of action, as many Chinese cities are already supplied with manufactured gas. There is a need for a nationwide standardised approach to gas conversion.*
- *Sustainable gas market development critically requires a sound gas pricing policy to reflect the economic costs. This applies not just to the distribution companies, but to the whole of the gas supply chain.*

Natural gas development must follow a consistent policy, from the field to the end-user. However, up until now, downstream market development – distribution and end uses – has attracted very little attention in China. There seems to be no clear link between the production of natural gas and its consumption, except for some big projects (petrochemical, power production, fertilizer facilities, etc). There seems to be an assumption that once delivered at the city gates, natural gas would find its way to the final customer naturally. However, without a consistent downstream development policy, the gas will stay unused at the city gates with serious consequences for the development of the upstream sector.

This chapter addresses the issues of downstream market development. It attempts to identify a list of problems that need to be addressed in China's gas distribution sector.

THE CURRENT STATUS OF GAS DISTRIBUTION IN CHINA

Market potential

According to the Ministry of Construction, in 2000, China's gas distribution sector supplied 15.2 bcm of manufactured coal gas, 8.2 bcm of natural gas and 10.5 million tonnes of LPG. 176.3 million people were supplied with gas. They accounted for 84% of the country's urban (or more precisely non-agricultural) population[1]. 63% of them used LPG, against 13% using natural gas and the remaining 23% using coal gas. Only about 15 large cities and some small ones were supplied with natural gas.

1 These data are significantly higher than those provided by China Gas Association. According to the latter, there were only about 20 million residential customers in 2000 for all gases, which correspond to about 80 million people. The urban gas consumption numbers provided by the China Gas Association are also much lower than those of the Ministry of Construction. Source: http://www.chinagas.org.cn. A source from the China Energy Research Society suggests that by 2000, only 24% of the total population in China used one or another form of gas for energy purposes. This number includes 126 million of the rural population that use LGP, biogas, coal gas and natural gas.

By 2005, the Ministry expects that natural gas will be supplied in 148 cities and the urban distribution sector will use 20.2 bcm of natural gas. The number of cities using natural gas will increase to 270 in 2010, and city gas distribution will consume 41.4 bcm of natural gas, a volume that will represent about 35% of the total natural gas consumption in the country.

These projections are very optimistic. They show the potential for growth in the gas distribution sector in the country. Important barriers remain to be addressed, however, if such a potential is to be realised.

Gas companies

Gas distribution is carried out by municipal gas companies, under the control of municipal governments at the local level and under the supervision of the Ministry of Construction at the national level.

Many towns and cities have a gas distribution network, but just over ten large ones have a network dedicated to natural gas, as in Beijing, Shanghai, Chongqing, Xi'an, etc. The coverage of the natural gas network is still very limited.

Until recently, gas companies were placed under the direct control of the Municipal Bureau of Public Utilities and thus acted solely as operators of a network that was built by the town. Gas sales to customers covered the running costs of the company, with a complement subsidised by the municipality when necessary. Most of the investment costs were supported by the town.

Now, things are changing in many towns. The trend is to give gas companies a commercial status and to free municipalities from financing gas operations. This has led to the transfer of investment costs to gas companies and final customers. New distribution companies are also being created, with ownership varying from one city to the other, from joint ventures between Chinese operators to original types of ownership by the workers of the company (as in Dazu – Sichuan). International joint ventures are at an early formative stage. They mainly involve the Hong Kong China Gas Company (HKCG), which has already invested in gas distribution (substituted natural gas, i.e. LPG mixed with air) in several cities in Guangdong province.

Networks

By the end of 2000, the total length of urban gas distribution pipes was 89,458 km. It was composed of natural gas pipelines (33,655km), coal gas pipelines (48,384km) and aerated LPG pipelines (7,419km). This is fairly low given the size of the country.

The technology currently employed in these networks generally dates from the period of manufactured gas, that is, cast iron pipes sealed with oakum and cement. Most of these networks cannot be used to distribute natural gas without extensive and costly retrofitting.

There also exist welded steel pipes for natural gas distribution, but they are rarely cathodically protected[2]. In theory, medium pressure is used, but as the required supply pressure is seldom

2 Cathodical protection is an electric process by which a very weak current is supplied in the buried steel pipes to prevent electro-corrosion by a battery effect.

available, and in many cases the demand is higher than the supply, the network generally operates at low pressure. Furthermore, Chinese regulations limit the pressure to 8 bars in the cities (except in Shanghai, where some lines are supplied with a 15 bar pressure).

Polyethylene technology has been very limited, but it is beginning to be developed in areas where there is local production of the corresponding materials. When new networks are laid, which are specifically dedicated to natural gas distribution, imported materials are now being used, as in Chengdu, Xi'an, Shanghai and Beijing.

KEY PROBLEMS TODAY

There seems to be a lack of awareness in China of the important differences between natural gas and manufactured gas and their implications for gas distribution policies. These differences include:

- Manufactured gas is produced locally around the city, either from coal or from light petroleum products (LPG, naphtha, etc). It can be produced when needed. This is very different from natural gas, which is often brought in large quantity from a long distance, and the natural gas industry works like a chain.
- Natural gas, either transported *via* pipeline or brought to the port by LNG cargo, is characterised by its abundance. This gas must be sold quickly to justify the upstream investment and transportation. This is not the case for manufactured gas, for which the supply is characterised by its scarcity.
- Manufactured gas is humid, whereas natural gas is very dry. This means that the existing distribution pipes are not suitable for natural gas and there is a need for retrofitting the distribution network.
- Different heat content: manufactured gas, whatever its origins, has a low calorific value, under 5,000 kcal/m^3, whereas natural gas's calorific value is about twice that, between 8,000 and 12,000 kcal/m^3.
- Differences in the pressure needed to maintain the calorific output, with good combustion conditions in domestic appliances, which may require the conversion of the network.
- Differences in combustion velocity, which may induce a flame blow-off if nothing is done to prevent it.

Partly due to the widespread ignorance of these differences, China's gas distribution sector faces the following types of problems.

Management cultural gap

There exists, in China's gas distribution business, a big cultural gap between the management of "scarcity", which is the case with manufactured gas, and the management of "abundance" resulting from the delivery of natural gas *via* pipelines or LNG cargos. Characteristics of this type of "scarcity" management include:

- Little effort in gas marketing, including market surveys and demand evaluations;

- Little or no service to customers;
- Lack or low level of technical knowledge in the technologies to be used;
- No sector-specific offers or incentives to customers.

Relations with customers

Relations between the gas distribution company and its customers are minimal. Gas companies seem not to know what customers actually do with their gas and whether they use it efficiently or not. This can be attributed to the "scarcity" management concept referred to previously, which does not require any additional service to be supplied, and thus no marketing effort. Even when other entities commissioned by the local municipal government, such as the Energy Conservation Supervision Centre in Shanghai, were asked to do this kind of control, the results were generally not supplied to the gas distribution companies or the latter were not interested.

To create a market for natural gas, the gas distribution companies have to realise that they have customers, not just gas users – that is to say that selling gas is just one part of a deal which has to be completed by a set of services to the customers.

Metering, pricing and billing

Gas consumption is metered in volumetric terms in China. Up until now, there has been no local contractual quality for the supplied gas, whereas such a contract is highly desirable (Box 5.1). There is therefore no equivalence between volume and heat quantity. The heritage of the past explains this situation.

Box 5.1

Contractual Gas Quality

Depending on its sources, natural gas has different chemical compositions and therefore presents different heat value for the same volume. Even for gas from the same source, gas quality, in terms of heat value, pressure and temperature, can vary significantly for the same volume. For example, heat value can vary from 8,000 kcal to 12,000 kcal for the same cubic metre; and the same cubic metre can contain more or less gas depending on its pressure and temperature. There is a difference of about 10% between the gross and net calorific value of the same gas (see also Box 6.1).

Whereas domestic customers hardly see any real difference, due to their low consumption, industrial customers are very wary about this issue. There is thus a need to have a contractual quality to ensure that consumers pay for the amount of energy they get, not just the volume of gas. This will be especially needed when natural gas is supplied from several sources. For example, when natural gas was discovered in the south-west of France and was first distributed, the French gas company defined a contractual heat value of natural gas. But as the gas quality was the same everywhere in France, the billing system relied mainly on volume metering. The situation changed when France had to diversify its natural gas suppliers, and the contract was adapted to reflect this. The new contracts defined limits between what the heat value had to be, and this heat value was controlled at various strategic points along the transmission and distribution lines. These values were then used to calculate an average heat value to provide accurate billing to customers.

Manufactured gas is produced with quite constant characteristics and is distributed locally, mainly for domestic use, and in small quantities. Furthermore, the price for domestic use is low (subsidised). The rare industrial users, as well as commercial customers, paid a high price but were happy to be supplied with gas. Nobody seemed bothered by the energy content of the volume sold.

The same practice has continued for natural gas, until now. Towns are supplied with gas coming generally from one source, and the quality of the supplied gas remains constant. Gas distribution companies did not see the importance of binding volume and heat quantity and thus did not check the calorific value of the distributed gas.

With the diversification of sources, this will now have to be addressed by Chinese gas companies. The production companies will have to guarantee a heat value (at least upper and lower limits) as well as a specific gravity (or limits – for which it is important to keep the same characteristics for some kinds of flames).

The billing system is based on the metering of the volume of gas consumed and on a tariff often based on considerations that bear no relation to economics, but are mainly political. This results on the one hand, in low tariffs for domestic customers (whose consumption is low, but who entail high network investment costs) and in higher prices for commercial and the few industrial customers, on the other.

The price at the city gate is not really negotiated between the producers and the gas distribution companies. The former are large and powerful companies, whose margins may be quite important, and the latter are generally small and powerless and have no bargaining power.

To take an example, in the Pudong district of Shanghai, it has been said that the price of natural gas at the city gates was around 1.2-1.3 RMB/m^3. At present, in 2002, natural gas is supplied from the Pinghu offshore field to the city gate for 1.5 RMB/m^3 according to Pudong Gas. To be able to sell gas at an affordable price, the margin of Pudong gas is around 0.2 RMB/m^3. In the future, Shanghai will also be supplied from inland fields and the price at the gate is scheduled to increase to 1.7-1.75 RMB/m^3. This leads to a decrease of Pudong Gas' margins to zero, which is not a good omen for sales development. But Pudong Gas is quite a large company, and the Pudong area a very promising one, so Pudong Gas may be able to borrow money from the banks, or it may find some other partnership, thus buying time while waiting for better days. Other smaller gas distribution companies may not have the same advantages as Pudong Gas.

In some other cities with a long natural gas history, as in Chongqing, things are different. There the price for domestic users is around 2 RMB/m^3, and slightly below 1 RMB/m^3 for industry, mainly for fertilizer plants. Only commercial customers continue to pay a high price, between 2 and 2.7 RMB/m^3 depending on gas use.

Connection fee

When gas companies are asked to improve their commercial position, they often take a short-term approach by charging a prohibitively high connection fee to finance network expansion. The fee is 4,200 RMB for residential consumers in Chengdu city – the capital of Sichuan province, and 2,000 RMB for consumers in the countryside of that province. This is equivalent to six months' salary for an ordinary worker. The fee could be as high as 6,000 RMB in other parts of the country. This has led many potential consumers to refuse connection even when the distribution network is already built up to their doors.

In many cities, regulations require that any new building must be equipped with a natural gas connection. This makes the connection fee part of the real estate transaction. When a building is to be supplied with natural gas, a contract is signed between the gas company and the promoter in charge of selling the apartments. The promoter then sells on the connection at several times the fee he initially paid to the gas company. This completely blurs the gas issue, and sets up a "wall" between the gas distribution company and the end-user.

Lack of marketing and sales policies

Up until now, the distribution companies have had no real marketing or sales policy, due to the cultural gap between scarcity and abundance management already mentioned above. As there is no real sales development policy and no serious market survey, the gas companies are unable to forecast future demand, or evaluate trends in gas utilisation and the evolution of customer expectations.

With the development of natural gas in cities such as Shanghai or Beijing, a marketing approach was seldom used, due to the existence of a "wall" between the final user and the gas company.

What seems to be missing at present is the will to step out of traditional behaviour, which was based on the culture of manufactured gas. Part of the problem lies in the fact that all gas distributors are small operators confined to their own cities. As they are typically local, they are sometimes also prisoners of the local cultural and business environment, which makes them conduct business as in the past. Their small individual size also makes it difficult for them to adopt a systematic approach in terms of gas marketing.

One way to address this problem is perhaps to allow a successful gas distributor in one city to acquire distribution rights in other cities and to form a regional or national group for gas distribution.

Distorted economics of gas distribution

When dealing with manufactured gas, the economics seem to be quite simple. There is a production cost of gas, including the investment cost of producing factories, and a network laying investment cost, all supported by the municipality. At the other end, there are customers, most generally domestic (cooking and water heating) and collective (space heating). The price of the gas sold is defined according to rules that bear no relation to economics. Billing is made according to the volume consumed, with no relation to the real heat value of the supplied gas.

When natural gas is distributed, the practice is slightly different. Natural gas is supplied to the city gates by national producing companies or by joint venture companies, which define a quantity of gas to be supplied to the town, according to an evaluation of needs. But generally, the municipality, which often has ambitious development plans but has not carried out any serious study on demand build-up, asks for more gas than it can realistically sell, and a contract is then signed, possibly on a take-or-pay basis. This means that the consumed quantity is paid, but the gas which is not consumed also has to be paid, with an additional fine for not consuming it. This does not lead to the healthy development of natural gas sales.

There are no serious studies on the costs of the distribution companies. In any case, they have no effect on the price of gas, because gas pricing practice has nothing to do with the cost of providing the gas to individual consumers or with the market value compared to alternative fuels. (The problems related to gas pricing are exposed in more detail in Chapter 6). These problems have led to net financial losses for almost all the gas distribution companies. According to the China Gas Association, the gas distribution companies made a total loss of RMB224 million in 2000, despite a total of RMB1,082 million of subsidies provided by the public sector.

The economics of gas distribution is further distorted by the existence of "walls" between the customer and the gas company as described above in relation to the connection fee. Other walls exist, as there is seldom any direct service relationship between the gas company and their customers.

These problems will have to be addressed for the natural gas distribution sector to develop and realise its full market potential. A sound distribution sector needs to:

- Ascertain, based on serious market studies, the availability of natural gas in a sufficient quantity, with a contracted quality.
- Be able to distribute it in safe conditions, whatever the demand.
- Be able to sell it at a price that is competitive compared to alternative fuels and that every customer can afford, in good metering conditions.
- Be able to supply customers with additional services.
- Be able to forecast the evolution of future consumption and to plan network expansion accordingly.

As many Chinese towns already use manufactured gas supplied through a distribution network, a very important technical condition to increase the supply of natural gas is the conversion of the existing network and equipment.

ORGANISING THE CONVERSION TO NATURAL GAS

The main purpose of gas conversion is to carry out the required modifications to the network and to different existing equipment for them to operate correctly (with same power output, combustion safety and flame stability) using natural gas, whose characteristics (calorific power, specific gravity, combustion velocity) are different from those of manufactured gas.

The operation has to be prepared long before natural gas is delivered at the city gates. It also involves networks and related devices (pressure reducers, meters, etc.) as well as end-user equipment (domestic appliances, collective and industrial equipment, etc.).

The arrival of natural gas must also be considered as a unique occasion to modernise industrial and commercial installations, and as an excellent opportunity to improve their safety conditions of operation.

Conversion of the network

Manufactured gas, whatever its origin (naphtha, LPG, coal), or coke oven gas, is humid, which means that it contains water and cyclic hydrocarbides, and the seals used (rubber seals for cast iron networks, oakum and paste for screwed indoor steel pipes) will not dry. With natural gas, which has been dried at the treatment plants before transmission, these seals will dry, inducing leaks.

If the currently distributed gas is produced from light liquid petroleum products (e.g. naphtha) which are dry, it may be economic to continue manufactured gas production using natural gas as a feedstock during a transitional period, which helps buy time to complete the different conversion operations. The conversion will begin with the retrofitting of the gas production plant, which consists of the following steps:

- Study the most appropriate cracking technology to be used for a minimum cost.
- Carry out the modifications on the production unit.
- Lay a supply line from the city gate to the production facility and to the different production units, delivery station included.
- Check the consistence of the produced gas with the users' equipment.

But this should only be a temporary solution, as the economics of cracking natural gas for supply in a network of naphtha-based manufactured gas may not be justified over the long-term.

For networks based on manufactured coal gas, the conversion involves the following steps:

- Dividing the distribution network into several areas for conversion one after another.
- Perform the work on the distribution networks to check its usability with natural gas, taking into consideration that natural gas has to be distributed under a higher pressure than manufactured gas to maintain the equivalent power of appliances.
- Install new service boxes and, when required, new meters (all those which are not of a dry type must be replaced).
- Control indoor installations (risers in buildings, generally of the screwed type with

manufactured gas, must be retrofitted to change the seals, all flexible pipes connecting appliances to the indoor network must be replaced, if possible by screwed connections, etc.).

Conversion of end-user equipment

To operate properly in safe conditions, gas burning equipment requires steady and hygienic combustion, sufficient calorific output, and no deposit on elements in contact with the flame or with the combustion products.

All the considerations on the conversion of domestic appliances are based on the notion of "interchangeability". Three requirements must be met:

- Keep the same quantity of heat supplied by the appliance as before.
- Bring a sufficient quantity of air to guarantee good and safe combustion, as natural gas needs around 13% more air than manufactured gas to obtain complete combustion.
- Correct the effect of a decreased combustion velocity.

To meet these requirements, some transformations must be made in dedicated workshops, or in a specially designed working van, or in the user's dwelling. Some pre-conversion[3] operations may be made in order to limit the period of immobilisation of the appliances during conversion.

Beside the conversion of networks, the gas distribution company must prepare the conversion operation of appliances by:

- listing all its customers, whatever their individual consumption level.
- listing all appliances and listing those which can be converted.
- preparing an advertising campaign to induce customers to replace appliances which would not operate properly after conversion, and eventually study incentives for them to do so.

For industrial customers, individual solutions have to be designed, with the help of manufacturers of equipment (local or foreign) and/or of specialists in this field, for each piece of equipment (burners, furnaces, etc.). A complete list of these customers has to be made, with an accurate description of each piece of equipment (hourly and daily consumption, operating conditions, etc.).

Such a conversion operation requires at least 18 months (Box 5.2) before natural gas is available at the city gates, depending on the size of the distribution network and the number of customers.

3 Pre-conversion is necessary when appliances are old. The purpose is to limit the immobilisation period of equipment during conversion. During the pre-conversion phase, injector holders are placed, as well as swirl screws, holes are bored, but provisional injectors allowing good combustion with the first delivery of gas are put in. Hence, when conversion takes place, these injectors only have to be changed and the aeration ring adjusted.

Box 5.2

Standard Timetable for Gas Appliance Conversion

Time	Key Task
M – 18	Listing of the customers connected directly on the high pressure network (if any).
M – 16	Naming a conversion manager.
M – 15	Listing of commercial and industrial customers, to be sent to the company in charge of conversion (if any).
M – 14	Designing the conversion programme. Cutting out the conversion areas.
M – 15 to M – 8	Public relations operations to explain what will happen.
M – 15 to M – 7	Gas company workers' information. Training of surveyors. Training of technical staff.
M – 13	Publication of the final cutting off of conversion areas. Publication of the conversion programme.
M – 10 to M – 9	Deliver the list of all customers to the conversion company.
M – 8 to M – 7	Supply the conversion company with a survey of commercial activities.
M – 7 to M – 6	Beginning of the survey.
M – 5 to M – 4	Supply the conversion organism with a technical building to prepare the conversion of industrial and commercial equipment.
M – 3	End of the commercial activity with all appliances for replacement ready. Notify the clients about the necessary changes to be made in the park of equipment due to the conversion.
M – 2	Supply the conversion company with a technical building to prepare the conversion of domestic appliances.
M – 1	Beginning of the possible pre-conversion of domestic customers.
D – 8	Send letters of "Conversion Advice" to customers.
D – 3	Remind customers of the instruction.
D	**Gas switching operation on the network. Check conversion works on equipment**
D + n	Letters to customers to thank them for their co-operation and ask them to state their observations as soon as possible.
M + 2 to M + 4	End of the conversion work, in agreement with the gas company and the conversion company.

Note: M and D are respectively month and day relative to the day of the conversion

In cases where existing appliances cannot be retrofitted, the customer must be offered a choice of new natural gas burning appliances, which must be easily available, in co-operation with appliance manufacturers.

ENSURING THE SECURITY OF SUPPLY

Security of supply is a vital aspect of the gas distribution business. It can be defined in relation to the following types of risk in gas operations:

- The short-term risk of supply disruption, which can be caused by accidents or other technical problems such as extreme weather conditions, that lead to the failure of markets to adequately balance supply and demand.
- The long-term risk caused by inadequate investment in upstream and transmission activities to secure future supplies. The lack of diversity in gas supply sources also contributes to the long-term risk.

Long-term gas supply security

Long-term gas supply security clearly affects the gas distribution business, but it obviously goes much further and should be an important concern for national and local governments too. It involves the issue of investment to develop gas reserves, engage in production, and build pipelines to demand centres. Investment in those upper-stream areas can be sustained only if there is a sustained cash flow that goes in the opposite direction to the gas flow. This leads to the issue of gas pricing at the distribution sector and to the long-term commitment of gas distributors to buy gas. The financial health of the distribution sector therefore directly affects the long-term security of gas supply.

The level of concern about long-term gas supply security varies from city to city in China, mainly depending on the local situation. It is of less concern for cities that are located close to substantial gas reserves, such as Chongqing, but becomes more pressing for cities such as Shanghai and Tianjin, where gas is supplied from remote sources. These cities are also seriously looking into the issue of supply diversification, as they do not want to become too dependent on a single supply source for a large share of their gas needs.

Short-term supply security and modulation

Short-term gas supply security requires dealing with supply disruption as a result of technical accidents in the gas production and transportation system, as well as coping with demand variations, either the usual demand seasonality or a very strong variation due to extreme weather conditions. Demand also varies daily and hourly, which calls for a good system of supply modulation at the distribution level.

At present, the seasonality (winter peak *versus* summer valley) of the gas demand in China is low, around 1 to 2 for China as a whole. The main reason for this is that most of the space heating comes from collective units generally using coal. But in some cities such as Beijing, the seasonality factor is very high, about 1 to 6. This level of seasonality is not dramatic. In France for example, the monthly variation in 2000 was from 1 (in August) to around 7 (in January), with a peak daily variation (between the day with the lowest consumption and the day with the highest consumption) above 10. As the gas market develops in China, the variations in demand will also increase. Thus, there is a pressing need to develop a gas supply modulation system to cope with these variations. This calls for a quite complex system of management and co-ordination between distribution companies and high-pressure pipeline transmission companies.

As described in Chapter 7, gas pipelines need an important volume of gas storage to cope with either technical accidents in the pipeline operation or with extreme weather conditions. Underground storage facilities, namely depleted gas fields, salt caverns or aquifers, are usually placed under the responsibility of production or long-distance transmission companies as they will have to be used along the transmission lines. In addition to these storage facilities, the following gas storage types are available to gas distribution companies:

- Oversized medium pressure pipes (or Line-Packs), which allow an additional supply by lowering the pressure.
- High pressure spherical tanks, which are able to store between 10^5 and 10^6 m^3 of natural gas under a 10 bar pressure. The available volume is relatively low and the investment cost high. This is the technology used in Xi'an and Chengdu.
- LNG peak shaving facility (*in situ* liquefaction – LNG storage – regasification), which has a higher storage capacity (between 10^7 and 10^8 m^3). It may cover the seasonality of the demand and in some cases improve the security of supply of a larger consumer area. This technology has been used in Shanghai's Pudong district. The corresponding investment per unit of storage volume is around three times lower than that of spherical tanks.

Currently, two problems arise in the relationship between pipeline operators and distribution companies on the question of supply modulation. First, the pipeline companies' appreciation of the degree of demand variation, which is 10% around the seasonal average, is not large enough to cover even the daily and weekly peaks. They should increase the coverage to at least 20% around the seasonal average.

Second, individual cities tend to deal with most of the peak shaving operations by building their own storage systems (LNG, high-pressure tanks). These means of storage are very expensive, amounting to as much as US$20-35/cubic metre of storage capacity, compared to the cost of underground large-scale storage, which could be as little as US$2.5/cm of storage capacity. Hence, the rational approach would mean that gas storage should be aggregated to have economics of scale and should be under the responsibility of transmission companies. Thus, instead of building their own expensive peak shaving facilities, LDCs could share a maximum common storage facility. This type of common storage would have to be underground. It should be managed by the transmission company for an additional cost at the city gate. This additional cost, reflecting the investment depreciation and the operational costs of the underground storage facilities, would largely be covered by savings in individual facilities. Good co-ordination between the transmission company and the distribution companies along the pipeline is indispensable in managing such a system.

In addition to storage facilities, gas distributors can also have other security means that include demand-side measures to cut the peak demand, to introduce interruptible contracts and dual fuel systems such as co-generation using both gas and light oil with the same turbine. Interruptible services (Box 5.3) to large customers constitute a good measure to improve short-term supply security for small customers who have more difficulty in fuel switching. Currently, this type of contract will have value only for large industrial customers, including power stations, which will have to be equipped with dual-firing systems and to have an alternative fuel at their disposal.

Box 5.3

Interruptible Gas Supply Contracts

The use of interruptible contracts is common in most gas markets. They usually apply to large customers that have the ability to switch fuel at short notice. Under this type of contract, a gas supplier (a pipeline operator or a local distribution company) has the option, under certain conditions such as too heavy load, to interrupt gas delivery to a customer within a predefined period of notice without being penalised. The interruption usually takes place in peak load seasons in order to supply the available gas to firm-contract customers and higher priority users such as residential customers.

When called about an interruption, a customer will generally be provided with the following information:

- Site of gas to be interrupted;
- Volume of the interruption;
- Start time; and
- Estimated duration.

Customers should then make the necessary arrangements to switch to alternative fuels or use other contingency arrangements by the time specified.

The use of interruptible contracts improves the efficiency of pipeline and distribution systems by increasing their load. These contracts normally only apply to consumers who have the ability to switch to alternative fuels. The price of interruptible service is typically heavily discounted to compensate for the burden on the user to maintain an alternative fuel option. However, under this type of contract, services may not be interrupted when the system load is light and the supply is adequate.

GETTING THE ECONOMICS RIGHT: GAS DISTRIBUTION COST AND PRICING

One of the most important issues in China's gas distribution sector, and perhaps the most important long-term issue, is to get the economics of gas distribution onto the right track. This involves:

- Negotiating the city-gate price based on the net-back market value of gas as compared to alternative fuels;
- Clearly identifying the costs; and
- Accurately reflecting the costs in gas prices for different end-users.

The net-back pricing approach based on the market replacement value of natural gas is discussed in Chapter 6. To ensure that gas is sold at competitive prices to final consumers, while at the same time distribution companies recover their costs, it is critical that the city-gate price is determined on the basis of the average market replacement value of the consumers within the city, minus the costs of the distribution company. It is only under this precondition that gas distributors can pass on their costs to consumers without affecting market size. These costs will have to be clearly identified.

Costs of gas distribution companies

A gas distribution company takes its contracted gas from its supplier at the entry point of its own system (normally called city-gate) and brings it to end-users at the required volume, in the required form, and at the required time. It involves the following costs:

- Gas purchase cost: this is the price that the distribution company pays at the city-gate. It is supposed to cover all the costs that are incurred so far (production, processing, transportation and supply flexibility), plus tax and profit for the upper-stream players.
- Capital costs for investment in low pressure gas distribution grids, pressure reduction stations, gas storage facilities and gas meters. These are often translated as depreciation cost in the gas company's account book.
- Operating costs, which include a variety of items like the purchase of goods apart from gas and investment goods, purchase of services from sub-contractors, insurance, public relations costs, postage and communications, etc.
- Salaries, social charges and pension provisions.

Only the gas purchase cost is called the gas cost and all other costs are grouped as non-gas costs. The non-gas costs can be further divided into fixed costs, which are independent of the gas sales volume, and variable costs, which are related to the sales volume. The per unit distribution cost is then added to the average market replacement value to give the city-gate price for the distributor to negotiate with gas producers and transmission companies.

Pricing distribution costs to end-users

In IEA countries, the pricing structure charged by local distribution companies to end consumers varies significantly from country to country. The tariff structure of a country depends not only on the pricing approach (either cost plus or market value) taken by gas companies, but also by regulatory models of the country (Table 5.1). In reality, the tariff structure in most countries has elements of both the cost-plus and the market value approach.

France adopted a cost-plus approach for distribution gas pricing. The tariff system of *Gaz de France* is sophisticated and features seasonal variations and volume rebates. The price consists of a subscription fee, a capacity charge and a commodity charge. The latter is by far the most important element in the final prices. The United States have a cost of service approach. The rate structure usually consists of two parts: a base rate, which provides a fixed cost recovery and a return on capital investment; and a volumetric rate that is based on the amount of gas purchased or transported. This traditional rate structure is supplemented by a variety of non-traditional rates such as market-based and incentive-based rates. In Germany, where the pricing approach is based on market value, gas tariff consists of a capacity charge and a commodity charge. 30% of the capacity charge is linked to salaries and the remaining 70% to the light heating oil price. The commodity charge is exclusively linked to the price of light heating oil. The Netherlands also has a market value approach; the price charged by LDCs has three components: a connection charge, a standing charge and a commodity charge.

Table 5.1

Gas Distribution Pricing Approach and Regulation in IEA Countries

Country	Pricing Approach	Regulatory Authority
USA	Cost of Service	State Public Utility Commissions
Japan	Cost plus	Ministry of Economy, Trade and Industry
France	Cost plus	Ministry of Economic Affairs
Germany	Market value with reference to light heating oil	
United Kingdom	Cost of service	Office of Gas Regulator (price regulation is required only for small users)
Netherlands	Market value with reference to light heating gasoil for small consumers and to heavy fuel oil for large consumers.	Light-handed regulation by Ministry of Economic Affairs
Italy	Market value plus elements of cost plus	

Source: Natural Gas Distribution Study, IEA, 1998.

Designing an appropriate distribution tariff structure is not an easy task, as it has to meet the following objectives:

- encouraging gas substitution for alternative fuels;
- recovering gas purchase costs;
- obtaining a reasonable rate of return on capital investment;
- recovering operating costs for gas storage, transportation and supply facilities; and
- encouraging a stable load factor in gas consumption.

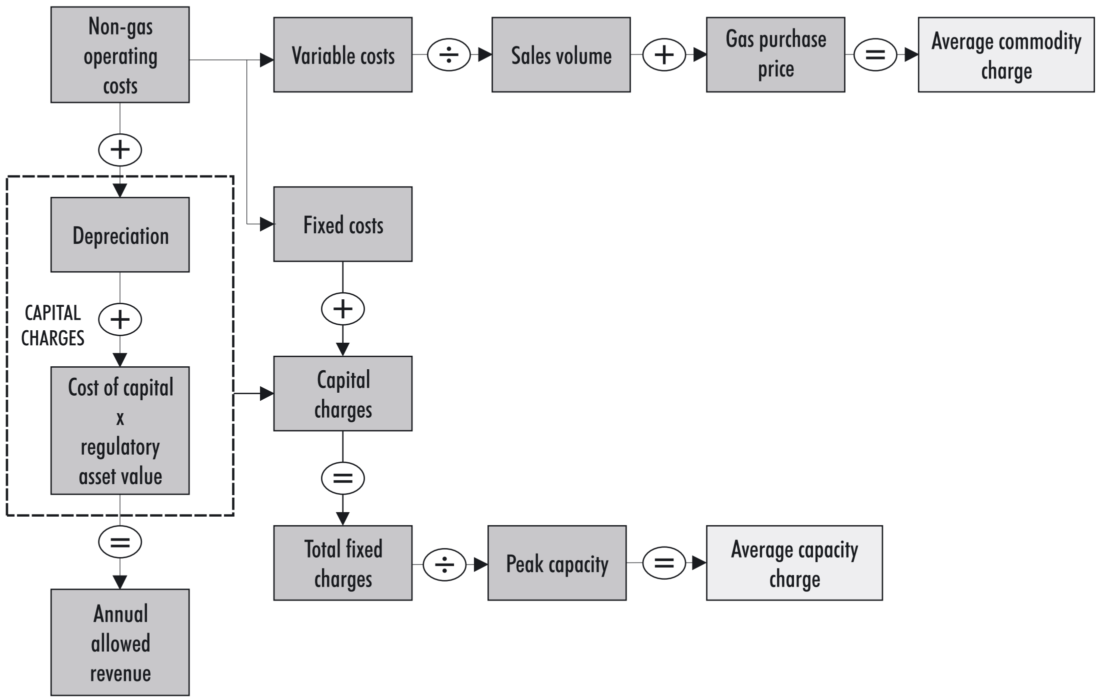
To meet the objective of encouraging gas substitution, a gas pricing approach should be based on market replacement value, as will be discussed in Chapter 6. This requires that the city-gate price be set according to net-back market value as argued above, not arbitrarily set by the government or gas producers.

To meet the other four objectives, China could possibly adopt a gas tariff structure with the following characteristics:

- It should comprise a subscription or connection fee, a fixed capacity charge, and a commodity charge.
- The connection fee is a one-off contribution by the gas consumer to the cost of connection to the gas systems. It should be set at a relatively low level for small consumers to encourage connection. For large industrial users it could be higher, provided that the gas price is lower than alternative fuels, which would allow the amortisation of this connection fee. The connection fee should not attempt to replace the role of fixed capacity charge in investment recovering.
- The fixed capacity charge is an annual charge paid by consumers to cover the fixed cost of maintaining their connections. This should reflect the load factor of individual consumers to encourage the even distribution of the gas off-take across the year. The commodity charge should recover the gas purchase cost and the variable costs of the gas company. Figure 5.1 illustrates how these two charges are calculated from gas costs, non-gas costs and costs of capital. For billing purposes, these charges are usually averaged and simplified by combining them into a single per unit charge for different categories of customer (according to their load).
- The tariff should also distinguish between gas consumption in the summer and in the winter, in that both the capacity charge and commodity charge should be lower in the summer.

Figure 5.1

Translating Gas Distribution Costs into Tariffs



Source: IEA analysis.

This structure reflects the cost-plus approach that is widely used in IEA countries. In designing a practical tariff structure for individual distribution companies, China will obviously have to allow for the need to encourage gas consumption. It could set the maximum price at which gas remains competitive with alternative fuels, taking into account the costs of gas supply and a return on investment. The market replacement value, as described in Chapter 6, could serve as a benchmark.

In the tariff structure, the explicit reference to alternative fuels is particularly important for industrial consumers. As a big part of industrial energy use is exposed to competition from other fuels, the market-value approach should prevail in gas pricing. Rate structure should be digressive with volume to encourage consumption and should reflect the load factor of the consumer.

It should be noted that the typical practice worldwide is for industrial customers beyond a certain size to be served directly by transmission companies. But the borderline between pipeline company and distribution company is not very clear or consistent. In some cases the customer is provided with a choice between the two.

The gas distribution sector is usually the target of regulation, which involves both licensing or awarding concessions and price regulation. Gas price regulation for the distribution sector will be discussed in Chapter 6, while issues related to distribution concessions are addressed in Chapter 11.

POLICIES AND MEASURES TO DEVELOP DOWNSTREAM GAS MARKETS

Developing the downstream end-users' market requires certain conditions. They include:

- A consistent pricing policy, which requires close co-operation between the different actors of the gas chain, from the producers and transporters to the city offices in charge of development, to the gas distribution companies. On the one hand, a poorly defined relation between upstream operators and downstream gas distribution companies may lead to erratic prices, or be interpreted as such. On the other hand, an insufficiently prepared evaluation of the existing and potential users' market may lead to erroneous conclusions, hence the potential for conflict, leading to unsatisfactory market development.
- A change in the business behaviour of gas distribution companies. To accompany market evolution, gas companies must create new relations with their customers. Paying users are customers with their own expectations, which have to be met by the distributor. The distribution company supplies not only natural gas, but the services associated to its use (counselling, technical help, etc). One solution, which produced very good results elsewhere, is to create new jobs in relation to marketing policy. This usually involves new engineers who must be able to answer technical questions, as well as produce financial studies according to the customer's situation, within the framework of predetermined rules. This will require them to maintain a good relationship with manufacturers and research institutes, which thus become natural interlocutors with a common interest in the development of the market.
- Good market development requires maximum safety conditions in all end-use sectors. Reliable standards and technical rules must be set in close co-operation between gas distribution companies, gas associations and official bodies.
- The introduction of good practices in the gas distribution business. This could be achieved through an improved environment for foreign investment in the distribution sector.
- Good marketing efforts with sector-specific incentives for gas users.

The gas pricing policies and practices discussed above are analysed further in Chapter 6. The other subjects raised are elaborated below.

The marketing approach

As explained in Chapter 3, natural gas is driven by demand due to the fact that alternative fuels are available for nearly all its end-use applications. Although there are obvious advantages to using gas compared to alternative fuels, such as environmental benefits, efficiency improvement and process innovation, potential users may not request the change of their current energy supply on their own initiative.

To develop gas sales, it is necessary to induce customers to buy natural gas, and thus offer efficient and specific equipment. New lines supplying natural gas must be made profitable by connecting additional customers. This involves the identification of potential customers in the existing or planned network area, conducting door-to-door sales, and defining a potential contract with those who are interested.

To do this kind of marketing, the salesmen from the gas company must also be technical engineers, able to explain the advantages of natural gas use in a given situation. They should have commercial training and technical knowledge. When necessary, they should be able to call on company engineers for help with more sophisticated technology issues. A tailor-made solution must be proposed to large industrial customers. This needs strong collaboration with gas equipment manufacturers. The search for solutions to specific problems can often result in new specific equipment, which could eventually be patented and developed under licence by the manufacturers.

In China, there exists a strong research capacity. What is missing are the technico-commercial engineers for the marketing effort. Their input is needed to bring about a change in the cultural practice of gas distribution companies.

The new marketing policy must deliver a very strong message to potential users: the arrival of natural gas provides a unique opportunity to modernise production tools. It may help make substantial energy savings. It could help to improve the environment. But at the same time, it requires improving or adapting the existing standards related to gas, as natural gas demands new operation conditions, and it must lead to safety improvements while also supplying new guarantees on the performance of a given piece of equipment. The gas user, existing or potential, must now be considered as a customer and no longer just as a user.

Maximising safety conditions

Developing the network in safe conditions at minimum cost is made possible by using new technologies, even if existing standards have to be adapted to include these technologies. This subject has been discussed extensively in China, and these techniques are already being used in some Chinese towns.

Safety requires a thorough scrutiny of currently available pipeline laying and connection technologies, through a complete quality concept. This particular subject is not developed in this report, but such an approach could be designed in co-operation with other experienced gas companies.

A comparative study carried out a few years ago by a European gas company in co-operation with Chinese researchers concluded that when they existed, Chinese safety standards were less stringent than European ones. So there is a clear need to improve existing standards and establish new ones.

Attracting foreign investment

The gas distribution industry is a capital- and technology-intensive industry, which has relatively high capital and technical barriers to entry. The safe and reliable supply of gas to millions of individual customers requires a high degree of industry expertise and technique. Unlike the wholesale business, the retail distribution business involves hands-on customer care, service, and marketing skills that require an in-depth understanding of the local market. While most jobs need to be done by the Chinese themselves, experienced foreign companies do have important expertise to offer.

China's urban gas distribution market has huge theoretical potential, with the large number of mega-cities that often count more than 10 million inhabitants. However, starting business in this sector is not an easy undertaking. First, as gas distribution is a retail-oriented business, a distributor should have a good understanding of the local market, the culture and the language. For this, they need Chinese partners. However, those partners, usually the local distribution companies (LDCs), are generally inefficient loss-making divisions of municipal government that lack management skills, industry expertise and capital. Until now, the majority of them have only been involved in the distribution of coal gas. Second, the lack of market transparency and the high level of regulatory uncertainty represent significant risks for investors.

Foreign companies wishing to invest in China's distribution sector need, of course, to understand the local business environment and practices. It would also be extremely beneficial for existing Chinese distributors to learn more from experienced foreign companies regarding marketing, capital management and investment strategies. In this regard, it is encouraging to note that urban gas distribution has recently been removed from the list of prohibited areas for foreign investment in China (see Chapter 10).

Sector-specific gas sales policies

To develop the gas market, national policies will certainly be needed, in particular policies and regulations related to environmental protection in urban and suburban areas. To supplement these national policies and measures, there is also a need to develop sector-specific gas sales policies. Such policies should take into account the following characteristics of natural gas use in these sectors.

Industry and commercial uses

Industrial and commercial users should be convinced of the advantages of using natural gas, such as its cleanliness, high heat value, ease of control and better energy recovery than other fuels, etc.

Furthermore, they should be convinced that the use of natural gas may lead to a new process design, to the modernisation of current installations, and to a better solution to specific needs, such as the decentralisation[4] of heat distribution in some industries like the textile, paper or agro-food industries.

4 In short, decentralisation consists of replacing a centralised boiler supplying heat to all the production units with specific equipment for each production unit. Decentralisation improves the versatility of operations, while demanding less total heat, hence improving energy efficiency.

Public and collective buildings

A public building, whatever its function, consumes electricity and heat (hot water, space heating, and perhaps cooking). At present, electricity is supplied by a public utility, and heat comes from a heating unit using coal, oil products or manufactured gas. Converting boilers to natural gas is a simple and cost-effective solution. It will lead to some energy savings (about 10 to 20%, depending on the technology).

But natural gas may also be considered as an opportunity to modernise facilities and eventually offer new energy uses. For example, a boiler can be replaced by a co-generation system, the capacity of which is calculated on the heat demand of the building. This will provide a given electricity supply, which may have to be completed by the grid if necessary (or the surplus sold to the grid, under conditions to be agreed with the electricity company). Co-generation units are now available on the international market, small enough to meet the requirements of specific buildings or small housing complexes.

Air conditioning is another opportunity for natural gas. Water-Lithium bromide chemical compressors are now well developed, and some Chinese manufacturers already have a large range of equipment. If natural gas air conditioners have a 10% higher investment cost than electric ones, their operational cost is generally significantly lower[5]. As air-conditioning runs only in summer, it helps to decrease the gap between winter and summer gas uses.

Collective cooking and catering also represent a large potential market. Although some restaurants already use gas, most of them still depend mainly on coal or coal gas. Many different kinds of equipment have already been developed, in China as well as in foreign countries. Even if the latter are not exactly suited to the Chinese way of cooking, most of them can be adapted to meet these specific requirements (like steam cooking, roasting, etc).

Residential sector

At present, the use of gas in the residential sector is limited to cooking and sanitary hot water production. Space heating is generally supplied from collective heating units, either inside a building or for a group of buildings, or from district heating units.

With improvements in living conditions, many customers may want to have more control over their own consumption. Gas distribution companies may offer better pricing conditions as individual gas consumption increases and hence offers a better payback to the distribution network.

This means that customers will want individual heating systems and will take this opportunity to modernise their appliances. Thus a whole new range of appliances will have to be available on the Chinese market.

The safe and efficient development of this sector means that indoor installations will have to be made according to rules which aim at improving indoor safety. The current practice of prohibitively high connection fees should also be stopped. Capital investment cost in distribution

5 In Europe, natural gas air-conditioning can cost three times less than the electric solution for the same power output. The Shanghai case study shows that if the natural gas price is lower than RMB 2.5/cm, natural gas-fired air conditioning systems are cheaper than those fired by oil, coal gas and electricity.

facilities should be recovered over a long term (e.g. 30 years) through a sound gas pricing structure as discussed above.

Small private workshops, such as bakeries and laundries, must be included in the residential sector. These workshops are closely woven into the residential tissue and would be connected to the same low pressure distribution network. At present, they generally use coal or briquettes. A marketing approach could induce them to use natural gas and a whole set of natural gas equipment should then be offered. Developing such a market requires close co-operation between potential manufacturers and the gas distribution company. A manufacturer will only develop a given piece of equipment if there is a market, and this market depends on the will of the gas company to develop it.

RECOMMENDATIONS

Based on the above analysis, the following recommendations are formulated:

RECOMMENDATIONS ON LOCAL GAS DISTRIBUTION

The Chinese government should:

- Improve the financial health of the local gas distribution companies (LDCs), which is an urgent and serious task for the development of the gas market. Current gas pricing practices need to be changed/rationalised and a new tariff structure developed on the basis of sound economic principles. Only a financially sound distribution sector can provide the creditworthiness needed for long-term gas supply projects.
- Encourage LDCs to cross the existing cultural gap between manufactured gas and natural gas by developing an active gas marketing policy and programme. This must be based on serious market surveys of the current situation and future needs of consumers.
- Further open the gas distribution sector to foreign investment in order to introduce good management practices.
- Take appropriate measures to address the imbalance between numerous local distribution companies and a few large national producers and that between gas appliance manufacturers and electrical appliance manufacturers, if such an imbalance obstructs gas market development;
- Create a national promotion group for gas conversion, to be placed under the Ministry of Construction or under the China Gas Association, to define and promote rules and safety standards for gas conversion work.
- Oblige local distribution companies to define a contractual quality of gas with their customers.
- Encourage close co-operation between gas research institutes, gas appliance manufacturers and distribution companies in order to help gas market development and accelerate gas conversion work.

NATURAL GAS PRICING AND TAXATION

Don't try to jump over a big gap in two leaps: it doesn't work.
- Winston Churchill

Crossing the river by grasping the rocks.
- Deng Xiaoping

Highlights:

- *Natural gas pricing is critically important for gas market development. It should encourage both gas consumption, by providing incentives for energy users to switch to gas, and gas production, giving investors a fair and reasonable return. It should also ensure the viability of each link in the gas chain. To a large extent, the size and shape of a country's gas industry is determined by its pricing policy.*
- *The setting of prices for all parts of the gas chain should be left to market participants. The state should restrict itself to protecting captive customers against unfair use of market power and to using taxation to reflect externalities and provide incentives for the development of a gas industry.*
- *Over the past few years, China has implemented a series of gas pricing reforms to encourage gas production. It now needs to adopt a new pricing approach that would encourage consumption. This should involve the immediate decontrol of well-head prices for new gas production and a phasing out of price and volume setting for existing production. The decontrol of wholesale prices would pave the way for buyers and sellers to negotiate prices on the basis of the net-back market value of the gas in relation to competing fuels.*
- *China needs to reform its gas taxation regime to foster gas penetration by including incentives to use gas and disincentives to use more polluting fuels e.g. by imposing an excise tax on fuel oil; to encourage production by having an upstream fiscal system which favours investment into additional exploration and production; and to simplify the taxation system to have an upstream take, a profit tax and a consumption-type VAT.*

The first four sections of this chapter discuss the existing pricing system in China, its weaknesses, and how the pricing system should be reformed to foster the development of an efficient gas industry. The fifth section describes the existing taxation and rent-taking system and suggests how it might be transformed to facilitate the rapid development of the gas industry in China. The last section discusses elements of fiscal and price reform to promote gas market development.

CURRENT GAS ALLOCATION AND PRICING SYSTEM IN CHINA

In the past, under its strict state control and command economy, China had government-fixed commodity production, consumption volume and prices. After more than two decades of reform, this system has gradually disappeared, leaving just a few commodities still under this practice. Natural gas is one of the 13 commodities and services which are priced by the central government today.

Gas quota and allocation

The quota and allocation system for natural gas consists of setting a production volume for individual fields and a consumption volume for large consumers. Although the system has gradually weakened over the last few years, it is still in operation. Table 6.1 shows gas production allocation according to pricing regimes and to different producers. From the figures provided, it can be seen that the portion under the quota price represents only 25% of the total planned production. It is also interesting to note that the volume of planned production in 2001 was far below the actual level of 30 bcm.

Table 6.1

Gas Production Allocation in 2001 (bcm)

Allocation according to pricing regime for different consumer groups		Allocation according to companies for their individual fields	
Within-quota price	4.5	CNPC	11.4
Out-quota price	6.1	SINOPEC	2.4
Contract price	7.1	CNOOC	3.9
National total	17.7	National total	17.7

Source: SDPC.

Gas pricing

The central government, through the State Development Planning Commission (SDPC), plays a major role in setting gas prices. The SDPC establishes the prices at the well-head and processing plant as well as pipeline transmission. Tariffs for local distribution companies (LDC) are set by local governments through their pricing bureaux. These tariffs concern not only the gas prices, but also the connection fees when a consumer first applies for gas supply. Both gas price and connection fees are the subject of negotiation between the LDCs and local pricing bureaux.

There are two parallel pricing systems in place today: the traditional system that applies to projects that were completed before 1995, and a new system that applies to projects completed in 1995 or later.

There are mainly three well-head gas price categories:

- A quota gas price for the volume of gas sold within the allocated quota. Table 6.2 provides the quota gas prices set by the SDPC for the year 2001. It can be seen that under this regime, gas prices vary according to consumer categories and between Sichuan and other regions.
- A "self-sale" price for above-quota production. This "self-sale" price, however, must remain within a 10% fluctuation range of the guidance price set by the SDPC. This guidance price for 2001 was RMB 0.9/cm[1].
- A contract price that is freely negotiated between producers and consumers.

The first two price categories apply to those projects built before 1995, while the third category is applied to those built afterwards.

Table 6.2

Quota Prices for Well-head Gas in China in 2001 (RMB/cm)

For Sichuan Province		Other regions	
Fertilizer	0.520	Fertilizer	0.480
Residential	0.685	Residential	0.580
Commercial	0.925	Commercial	0.830
Others	0.645	Others	0.690

Source: SDPC.

The traditional gas pricing system for old projects

Historically, the main use of natural gas in China has been as primary feedstock for fertilizer production. As the Chinese government insists on low fertilizer prices to maintain farmers' income and agricultural production, natural gas prices have been kept to a minimum level. And once fixed, prices did not change for years. As basic costs were not covered by prices, producers had no incentive to develop exploration and production. For example, in 1987, the average national selling price of natural gas was RMB68.47 per 1,000 cm, while the average cost of production was RMB99.28.

In 1979, China produced 14.5 bcm of natural gas, but production declined to 11.9 in 1981. Production only resumed to the 1979 level in 1989[2].

To encourage gas production, the government has, since 1987, implemented a series of price adjustments:

- In 1987, well-head gas prices were increased and the two-tier pricing system was introduced to allow gas producers to sell the above-quota volume at a much higher rate.

1 China prices gas in volume terms, i.e. without reference to energy content or any precise definition of gas quality. Gas volumes in China are expressed as normal cubic meters and not in standard cubic meters. If one considers as an example 9,000kcal per normal cubic metre as standard heat value, and given that 1 MBTU equals 252,000 kcal and that the currency exchange of 1US$ equals RMB8.3, then RMB 1/cm is equivalent to US$3.37/MBTU.

2 Sources: Quan and Paik, *China Natural Gas Report*. Royal Institute for International Affairs and Xinhua News Agency, 1998.

- In 1992, gas prices were slightly increased and price differentiation for different end-users was introduced.
- In 1994, prices were substantially increased to almost double the level of 1992.
- In 1997, the then State Planning Commission increased gas prices again as part of its move to align domestic prices with international levels. Prices have remained unchanged since then, at the level shown in Table 6.2, except in some areas where well-head prices increased by RMB100 /1000cm in 2001.

Table 6.3

Evolution of Well-head Natural Gas Prices in China (RMB/1000cm)

	Sichuan Province		Other Provinces	
1982		80		50
1987	Within quota	130	Within quota	80
	Above quota	260	Above quota	260
1992	Fertilizer producer	220	Within quota for residential use	130
	Residential use	280	Within quota for fertilizer use	160
	Commercial use	480	Within quota for other uses	210
	Other industries	240	Above quota	330
1994	Fertilizer producer	470	Fertilizer producer	440
	Residential use	530	Residential use	460
	Commercial use	670	Commercial use	–
	Other industries	490	Other industries	520
1997	Fertilizer producer	520	Fertilizer producer	480
	Residential use	685	Residential use	580
	Commercial use	925	Commercial use	830
	Other industries	645	Other industries	690

Sources: Paik and Quan, *China Natural Gas Report*. Royal Institute for International Affairs and Xinhua News Agency, 1998.

While the main area for the government's intervention is the well-head price, the SDPC also sets the gas purification charge and transportation tariff. It also intervenes, through its local subsidiaries (the provincial Development Planning Commissions), in setting the final consumer prices by local distribution companies.

- *Processing fee:* For years the fee was constant at 0.04 RMB/cm. It has recently been increased to 0.05 RMB/cm and a rise to 0.08 RMB/cm is planned.
- *Transportation tariff:* For pipelines built before 1995, the transportation tariff is set by the SDPC based on the distance, but does not take into account either construction or operating costs. The distance-related tariff was only introduced in 1992; prior to that, transportation fees were charged only according to the volume transported. The transportation tariff was raised twice – in 1994 and 1997. Table 6.4 provides the tariff structure in 1997 (still in force today) for old projects. The tariff structure for pipelines built after 1995 is described in the next section.

Table 6.4

Natural Gas Pipeline Tariff Structure in 1997 (RMB/1000cm)

Distance (km)	<50	50-100	101-200	201-250	251-300	301-350	351-400	401-450	451-500
Tariff	38	43	48	58	63	68	73	78	83

- Local governments set tariffs for LDCs. As a result, final consumer prices vary greatly across the country and remain independent of economic cost and of competitive fuels[3].

The historical pricing system in China did not encourage the development of a healthy gas industry, for the following reasons:

- Prices were set lower than production costs, resulting in economic distortion and leaving no incentives to increase production.
- Gas prices were set irrespective of the prices of alternative fuels. Often they were set before the project was decided.
- Once set, prices are reviewed only occasionally. As a result, they cannot adapt to a rapidly changing economic, market, or retailing environment.
- City-gate[4] prices, including well-head price, processing fee and transportation charge, are tightly regulated by the government. However, LDC's tariffs to end-users are subject to a variety of local add-on charges [there were 16 (!) kinds of taxes for Sichuan gas in 1991], which created very high end-user gas prices.

Aware that these issues were hindering the development of the gas industry, the Chinese government began a process of pricing reform in 1997. While it is slowly and cautiously drafting new directives for new projects, substantial parts of the natural gas industry continue to function under the old regime of quota allocation and fixed pricing.

Pricing system for new projects

The most significant feature of the 1997 price reform policy was the introduction of a new pricing system called "new price for new line".

The new regime applies to all gas projects developed since 1995 (newly producing fields or newly built pipelines) and to all foreign-invested projects. It represents SDPC's first step towards the liberalisation of the Chinese gas industry.

3 The residential gas prices in 2002 are RMB1.7/cm in Beijing, RMB1.8/cm in Tianjin, RMB1.45/cm in Lanzhou and RMB2.1/cm in Shanghai,

4 The point at which a local distribution company takes delivery of gas from a transmission company.

The objectives of this new system are threefold:

- To take into account the real costs of projects[5];
- To allow reasonable profit when calculating the economics of a project.
- To move away from the quota/allocation system.

Under the "new price for new line" pricing approach, each participant in the gas chain proposes a price to the SDPC which then reviews, adjusts and finally approves the gas price. In the case of an integrated project, different prices will be set for different parts of the project (transportation, well-head, etc.), but all will be reviewed at the same time. The basic principle that guides the SDPC in its pricing decision is to keep prices affordable for downstream customers[6]. This new regime's advantage is that it includes many voices, which creates a good balance, but unfortunately it also slows decision-making.

Each price element is determined as follows:

- *Well-head price:* It is calculated as follows:
  - A base price [based on project cost, taxation, loan repayment, and Internal Rate of Return (IRR) of 12%].
  - A price adjustment formula. This price adjustment formula can be used by the SDPC and the project developer to adjust the final price, either to increase it to account for an environmental premium or to decrease it to reach market affordability, but the SDPC has the final decision. In a project proposal, the formula would take into account:
    - Costs of comparative and competing fuels in the target market (which in theory should include crude oil, oil products, coal and power, but in practice only focuses on oil products and power) with equal price for equal thermal value at a relative thermal efficiency.
    - Inflation *via* an indexation function.
    - Price ceiling and floor to predetermine the range of price volatility, in order to avoid price shocks for both consumers and producers.

- *Processing fee:* Under the new regime, processing fees remain set by the central government (i.e. the SDPC) at 0.05 RMB/cm regardless of the actual cost of processing, but should increase to 0.08 RMB/cm as is the case for old projects.

- *Pipeline transportation tariff:* The calculation is based on a cost-plus approach. The tariff is determined through calculation of the economic cost of the pipeline project, plus a 12% IRR (15% for foreign-invested projects), based on average pipeline throughput and a 10-year depreciation period. The calculation is similar to that of the well-head price, except that there is no price adjustment formula.

5 Real costs are difficult to determine as the depreciation period is difficult to assess, and as the throughput plays a decisive role in determining the per unit costs. Depreciation time used in determining tariffs in China seem to be unduly short, resulting in high specific rates, e.g. for the Jingbian–Beijing Pipeline. In addition, the throughput itself depends largely on the competitiveness of the gas which in a cost-plus price system depends on the throughput. Assuming a high throughput may lead to competitive costs which may enable correspondingly high sales. Conversely, costs which are too high may prevent larger sales, which could result in even higher specific costs of the infrastructure used. The Jingbian–Beijing pipeline seems a case in point for that difficulty.

6 For example, in the residential sector, the SDPC will reportedly attempt to maintain a final gas price that will limit total household fuel spending to 4-6% of the average household income in the target market, e.g. Beijing, Xi'an.

- *Downstream price:* This is also mainly based on a cost-plus approach, but it takes into account end-users' availability to pay, gas competitiveness *versus* other fuels, efficiency, and a cost-estimate for converting coal gas distribution networks to natural gas. A proposed price by the project developer is then submitted to the local pricing bureau for review, adjustment and approval.

Table 6.5 shows the composition of gas prices for residential customers in Beijing.

Table 6.5

Beijing Residential Price of Ordos Natural Gas in 1998 and 2001

Year	Well-head price	Purification cost	High-pressure pipeline fee	Local Distribution Charges	Final Price
1998	0.58	0.05	0.36	0.41	1.4
2001	0.58	0.05	0.47	0.6	1.7

Table 6.6 compares the two pricing regimes described above.

Table 6.6

Comparison of Pricing Regimes for Old and New Projects

	Old projects	New projects
Exploration & Production price	Price is fixed by SDPC, different for each end-user segment	Price is project-specific, based on a cost-plus approach and reviewed and adjusted by SDPC
Processing fee	Price is regulated by SDPC	Price is regulated by SDPC
Transportation tariff	Tariff is regulated by SDPC, based on distance, pipeline diameter and volume throughput.	Price is proposed by developer, and adjusted or approved by SDPC.
Distribution price	Price fixed by SDPC and local government, different for each end-user segment	Price is project-specific, based on a cost-plus approach and different for each end-user.

Source: Roberts S. & Gilboy G., Cambridge Energy Research Associates, 2001.

Intended further reform

The SDPC has reportedly been devising a new pricing system that will have the following features:

- Different prices for big and small users;
- Phasing out the two-tier (within quota and above quota) pricing system;
- A greater range of city-gate pricing to take into account local demand prospects, affordability, quality and thermal value of gas, etc.;
- An explicit range (premium or discount) for the price adjustment clauses, with the SDPC continuing to set the guidance price, allowing actual prices to fluctuate within a range of either 5 or 10%;

- Periodic review of the base well-head prices;
- Pipeline capacity charges which will be higher for peak users and will be different for uninterrupted users and periodical users; and
- "Take-or-Pay" contracts for large users.

At the beginning of 2002, the SPDC introduced well-head prices that include processing fees. While this and the other intended steps address some of the flaws of the existing system they do not address the principal problem – that prices are set by a state institution rather than the market players.

PROBLEMS WITH CURRENT PRICING SYSTEM

The introduction in 1997 of the new pricing system allows a greater degree of cost-reflectivity and attempts to take into account the competitiveness of gas *vis-à-vis* other fuels. Although the state has the final say in setting gas prices, the new system at least seeks to base contract prices on average project costs, including a profit margin, and gives the project developer the chance to make a proposal. Pricing and volume under this new system are no longer linked to a formal mechanism for allocating supply to end-users. The new regime also has some elements which try to take into account the prices of alternative fuels. The new price system seems to be a conglomerate of different approaches which do not fit together, and pricing decisions are finally subject to the discretion of the SDPC. In addition, the old system is still operational, so the problems related to it still exist.

Box 6.1

Gas Requires an Exact Determination of Its Energy Content

For energy content of hydrocarbons, the difference between the net calorific value (NCV) and the gross calorific value (GCV) should be taken into account. This difference stems from the fact that in the combustion process of hydrocarbons, water is formed, which is evaporated by the exhaust gas, thereby taking part of the energy released by the combustion. Due to the relative higher share of hydrogen in methane, which is the main component of natural gas compared to other hydrocarbons, the loss due to evaporation is larger (about 10%) for natural gas than for higher hydrocarbons (about 5%). Without devices to recover the condensing heat contained in the vapour developed in the combustion process, only the NCV represents useable energy and would therefore be the reference for comparison of the prices of competing energies. The energy content of natural gas metered is usually expressed in GCV, which is 10% higher than NCV.

While the quality of products of the crude oil refining process is usually defined by certain standards which directly or indirectly determine the NCV of the oil product, the GCV of natural gas – even after treatment – may vary significantly. Depending on the original composition of the gas in the reservoir (which may include methane, ethane, propane, butane but also other gases, e.g. nitrogen, sulphur, carbon-dioxide) and on the treatment of the gas[7], the energy content of a same cubic metre could vary from 8,000 kcal to 12,000 kcal. Also, the reference points for temperature and pressure play a role in determining the energy content of gas measured in volume terms: one standard cubic meter (Sm^3) is defined as a cubic meter at 15 degrees Celsius and at a standard pressure of 101,325 kPa. (1 bar) as compared to a normal cubic meter (Nm^3) which is defined at 0 degree Celsius and the same pressure. The difference is about 5.5%: 1 Nm^3 = 1.055 Sm^3.

These considerations may seem pedantic. However, the resulting potential differences are significant compared with the profit margin (per cubic meter delivered) in the gas business. As an illustration of the order of magnitude: in a market of 80 bcm/y, which represents a total market value of US$10-15 billion, 5% difference is easily translated into a volume of US$500-750 million per year!

The current gas pricing system in China reveals the following major inherent problems which need to be addressed to allow the healthy development of the gas industry:

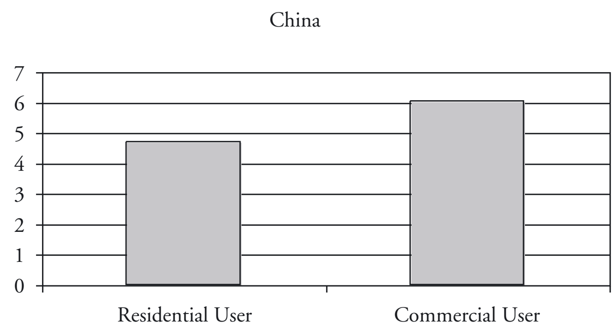
- First is a technicality, but an important one: Gas prices are set on the basis of volume, not calorific value, and there is no definition of gas quality for a cubic metre of gas in setting gas prices. The potential difference could be very significant (see Box 6.1), which could provide the basis for economic distortions and commercial disputes.
- The pricing system remains opaque to outsiders and is subject to political bargaining.
- The main point is that all prices are still finally set by a state institution and not by the market players themselves. The government-set or guided price does not and will never be able to adequately reflect changing demand and supply.
- Pricing is neither cost-reflective nor does it encourage market development. As will be discussed later in this chapter, for a gas industry like China's, with rather high-cost long-haul gas and imports, a market replacement value/net-back pricing system is adequate, as it gives maximum incentives to the development of a gas industry without fostering projects which are not able to compete in the marketplace.
- Although, in principle, the price-setting of gas at the well-head now takes account of the development of the value of the gas in end-use markets through the use of competing fuel price indexation in price-adjustment formulas, this is not *via* a net-back approach (see below) but just for indexation. So the starting point for a systematic approach is flawed, as it does not peg it to the development of competing fuels.

7 The treatment or processing would remove noxious gases like SO_2 to prevent health risks or damage to installations and recuperate higher hydrocarbons to the extent that such recuperation is profitable due to the higher market value of heavier hydrocarbons.

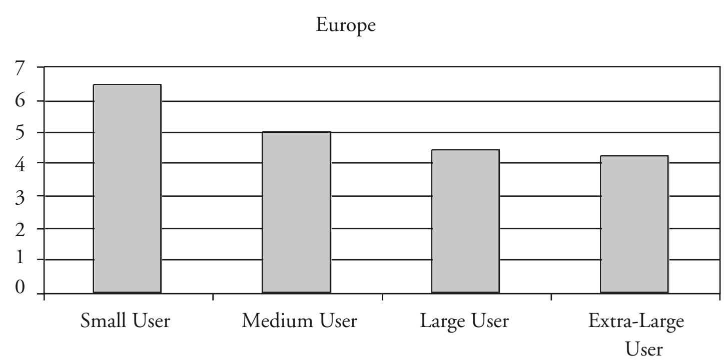
- The pricing system makes the pipeline segment the most vulnerable link within the value chain of a gas project. With pressure from both upstream, where sufficient incentives need to be given to resource developers, and downstream, where consumers need to have a competitive gas price, the midstream margins are often squeezed. This is usually achieved by cutting transportation tariffs. There have been several recent cases of such action, including a large cut in the tariff for the Ordos-Beijing pipeline. For the Ordos-Beijing gas pipeline (864 km), a 0.74 RMB/cm tariff based on cost calculation was proposed to the SDPC, but only 0.36 RMB/cm was approved without any compensation. Similarly, for the Zhongxian-Wuhan gas pipeline, it was reported that a 0.36 RMB/cm tariff was proposed while a 0.27 RMB/cm tariff was approved.

Figure 6.1

Gas Pricing Approaches in China and Europe (Unit: US$/MBTU)



China: data using Beijing's case in 1998 where residential end-use price was 1.4 RMB/cm and commercial end-use price was 1.8 RMB/cm.
Typical residential use volume is 200cm/year, whereas typical commercial use volume is a hundred thousand cm/year.



Europe: data using French case in October 2001 where:
Small user: <100 Kcm/year
Medium user: 100K – 1 Mcm/year
Large user: 1-10 Mcm/year
Extra-large user: 10-50 Mcm/year
Other European countries have a similar pricing approach.

- When addressing costs, the present system has various distortions and does not create the right incentive structure:
  - The system of setting different well-head prices for different user categories involves a cross-subsidy from large industrial and commercial consumers to small residential users. To be in line with costs, the logical approach would be to establish a digressive tariff by which the unit price decreases as the consumption volume increases. As Figure 6.1 shows, the current pricing practice in China is contrary to this logic: the more you consume, the higher the tariff you pay.
  - The fertilizer industry takes the largest share of the gas produced (around 40% currently) and the gas price for fertilizer plants is significantly lower than for other consumers. In the 1997 price increase, gas prices for other consumers increased by 30-40%, while that for fertilizer production only increased by 10.6%. This shows the government's sensitivity *vis-à-vis* farmers, given their importance for the social stability of the country. However, it would be much cheaper either to import fertilizers or produce them from imported ammonia. There are high opportunity costs linked to the use of gas for fertilizer production instead of using the gas to replace high-cost or imported gas. It seems illogical to depend on imported gas for power production while refusing to import cheaper ammonia, especially as ammonia can be stored more easily. Lower gas prices for fertilizer production represent an indirect subsidy to the agriculture sector. The obligation for producers to sell natural gas to fertilizer plants at the lowest price does not encourage production, and represents a permanent distortion in the Chinese economy. Removing this price distortion is a matter of some urgency for China.
  - Pricing all along the supply chain takes no account of load factor[8]. The current system involves an implicit cross-subsidy from high load-factor customers to low load-factor customers, because there is no explicit charge for capacity, either in transmission and distribution or in production. As they are not charged for capacity, end-users have no incentive to maximise its use. As pricing is compulsory, nobody in the chain has the possibility to create incentives by giving rebates or changing the pricing system. As a result, there is a considerable gap between peak and valley demand periods. In 2000, the peak throughput of the Jingbian-Beijing pipeline was 11 million cm/d in winter, but only 1.7 mcm/d in summer, as gas in Beijing is mainly used for space and water heating.
  - The cost-plus approach as embodied in the new pricing regime does not encourage cost reduction or efficiency improvement, and in fact may lead developers to over-report costs and to difficult negotiations on true project costs. Combined with the *de facto* monopoly of the three energy companies in their respective geographical areas, this pricing approach provides little incentive for companies to reduce costs. In a situation of rather expensive gas, a cost-plus approach risks pricing gas projects out of the market.

8 Average daily system throughput (or consumption) divided by peak daily throughput capacity, normally expressed as a percentage.

- The practice of a single well-head price for a number of basins or fields ignores the differential in production costs associated with drilling, development, and production from varying well-depths or reservoir qualities.
- Project developers cannot get a rate of return significantly above the official rate (12% for domestic projects and 15% for foreign invested projects). A higher rate would be necessary to attract investment where the risks are particularly acute.
- The depreciation period for pipelines is set too low by the financing rules in China. It is currently 10 years in general and 14 years for the West-East Pipeline. This is very low compared to the international standard of 25 years and the physical lifetime of pipelines of 25 to 40 years. This may be part of the reason why the pipeline tariff has often been the target for bargaining. If, as part of its investment policy, China decides to maintain the short depreciation period for tax and balance-sheet purposes, it should reflect the real economic life of the pipeline in the design of its tariffs.
- The allowance for the cost of natural gas processing takes no account of project-specific factors, which can result in big differences in actual processing costs per cubic metre of gas throughput.

THE TRANSITION TO MARKET-BASED GAS PRICING

Apart from imported gas such as LNG, so far, most of China's gas reserves are rather high-cost and remote from the main consumption centres. The driver for the development of a gas industry in China is not to make use of abundant and inexpensive resources and to realise the rent to the benefit of the country's economy, but rather the relative cleanness of gas compared to other fuels and its potential to substantially reduce pollution in the cities and acid rain caused by coal consumption. The pricing system should therefore provide the incentives for the development of a gas industry to the optimum size which can be justified by the relative economic and environmental merits of gas.

As described above, the current gas pricing approach in China, as embodied in the new pricing regime, is essentially a "cost-plus" one. While this approach attempts to encourage gas production, it does not ensure that the resulting cost-recovery price for gas would allow it to be marketed. A cost-plus system which starts with the cost of production and adds all the costs of transportation, load management and distribution is not adequate for the situation in China. Such a system is more appropriate for cases of large and inexpensive gas reserves close to consumption areas. But even there, costs are not that easy to determine as most cost elements are long-term fixed investments, and financing and specific costs are highly dependent on utilisation. Added to that, costs in a non-competitive environment can be easily flawed. This explains why even in gas rich countries such as the United States and Canada this approach has been abandoned due to its ineffectiveness in sending accurate market signals to investors to stimulate competition.

In China, a sound gas pricing system has to start with the final consumers' willingness to pay, obviously determined by the overall costs of using alternative fuels – including taxes and a valuation of the environmental benefits of gas. These factors will determine the eventual size of the gas industry. If the price the consumer is willing to pay is not sufficient to finance the development of the necessary infrastructure, then it would be uneconomic to opt for gas. The government can, of course, influence consumers' willingness to pay by setting taxes and emission standards for gas and its competitors which reflect their relative environmental merits, or by eventually having a requirement to use gas in new building areas, justified by its environmental merits. The government can also foster a larger gas industry by removing any risks and uncertainties for investment in the gas sector resulting from the governmental or regulatory sphere. Such uncertainties lead to additional risk premiums for investors, thereby increasing – unnecessarily – the costs of financing and reducing the level of investment and the size of the gas industry.

Further reform of gas pricing will have to ensure the competitiveness of gas at the final point of sale and leave the decision-making to market participants.

It has already been proven that government-set prices distort the economics of the gas supply chain, and fail to give the market the signals and incentives needed to develop the gas market. The government of China should understand that developing a gas industry of the size they envisage requires bringing in competition and private investors. The government will have to take a decision on how much longer it wants to continue with a gas industry based on state-owned companies with prices set by the government.

If China wants to build up a new gas industry relying on private initiatives and market forces, then it should leave pricing decisions to the market. This applies to prices for deliveries to power plants, industrial customers, and commercial customers. A possible exemption might be delivery to households by a distribution utility. Pricing all along the gas chain should be left to the market players, with the state's role restricted to preventing anti-competitive behaviour and discrimination. This especially applies to free pricing for wholesale gas at the well-head and at the city-gate.

The concept of market replacement value

The starting point for market-based pricing of natural gas is the determination of its replacement value compared to alternative fuels for each customer. The replacement value of gas is defined as the price of gas at which the end-user incurs the same costs when using gas instead of alternative fuels such as coal and oil products, taking into account differences in heat value, efficiency and costs for the appliances or equipment necessary to use the energy, plus eventually the different costs of resulting pollution.

The market replacement value serves as the basis for price negotiations. Prices above the replacement value will make gas difficult to sell, as customers may then prefer to use alternative fuels that cost less for the same result. Usually gas will still be the fuel of choice, even if the quantifiable costs for using gas are as high as those of an alternative, in view of the low pollution and easy handling of gas which are often not reflected in the equation. For freely negotiated prices the replacement value is a benchmark for the parties. For administered prices – which should be restricted to prices to captive customers, who are mainly householders – the concept may serve as a benchmark for the authorities to judge if a distribution company abuses its dominant/monopoly position.

However, further up the gas chain the replacement value is replaced by the net-back value. The net-back value is derived from the weighted replacement value of all customers above the point considered, by subtracting the costs for distribution, transportation and load management, and other costs necessary to bring the gas from the point in question to final consumers with the required load factor transformation to serve those customers (see next section).

It should be emphasised that the translation of these concepts into gas prices is best left to contract negotiations between market participants, with the role of the state being to ensure that contracts are respected. In the case of captive customers who will be served by standardised contracts, translation of the replacement value into a gas tariff should be left to the distribution company, depending on its marketing policy, while the public authority could use the replacement value as the benchmark to prevent any market abuse.

The replacement value and net-back pricing approach do not provide a rent for the final consumer. Any rent is passed on to the upstream parts of the gas chain. With the net-back principle, the rent is passed on further up the chain; if this principle is applied, the profits gained by the distribution and transmission and storage service between customers and the point of production would not exceed the usual risk-adjusted profit on their investment and operation costs. This approach is suitable for countries which do not have large and inexpensive resources to bring to the marketplace. However, as part of this approach, it should be ensured that the extra rent in the upstream sector translates into investment back into the gas industry. Incentives such as extra tax breaks for investing profits into the gas sector could be provided, and the state would need to make sure that no entry barriers exist for new investors so that extra-high profits either attract more competitors upstream or are re-invested into further expansion of the gas sector.

A state administered net-back concept would have an advantage over a cost-plus system in China because it would start with what the consumer might be able to pay without incurring opportunity costs, and give the right signals to upstream investors. It risks, however, covering only half of the gap. It would still not be able to achieve the complex optimisation of volumes and prices, which can only be achieved by free commercial actions. To cover the other half, there need to be free negotiations of prices and other conditions based on a sufficient number of commercial actors.

The market replacement value of gas can be derived by determining the lowest price of natural gas against any competing fuel by taking account of the following factors:

- Price and heat content (usually in net calorific value) of the competing fuel;
- The “Premium” (or disadvantages if any) of gas that can be calculated, including higher efficiency of gas compared to other fuels, lower operating costs, lower maintenance and storage costs, and lower investment. In addition, lower costs to meet environmental standards may be factored in. Eventually, an internalisation of environmental externalities, to the extent they are not reflected in emission or pollution standards, should also be made. Box 6.2 provides an example of calculating the replacement value of natural gas against diesel oil for heating a household.
- Other advantages that are not easily expressed in cost figures, including clean combustion properties, flexible and comfortable application and security, and easiness of supply.

While the energy equivalence between gas and other fuels is relatively straightforward, differences in efficiencies and operating costs are slightly more complicated, but can still be easily allocated on a per energy unit basis. Differences in maintenance costs are more difficult, as the resulting premium depends on the utilisation factor. The most difficult is perhaps the determination of the premium for gas in cases where large investments are made and the per energy unit premium depends on many factors: plant build up, financing scheme, utilisation rate.

Box 6.2

Determination of Market Replacement Value for Natural Gas

The main purpose of the following calculation is to determine the price per energy unit of gas so that it will equal the price per energy unit of the competing fuel.

Suppose that a customer has a dual-fired boiler, which allows him to use either natural gas or diesel oil for heating and that the conversion efficiency of both fuels is the same (which is not the case in reality). So calculating the replacement value of natural gas is only based on the heat content of both fuels.

A typical NCV for diesel oil would be 10.1 kWh/litre and a typical GCV of natural gas is 11 kWh/ Sm^3. So the equivalent useful energy of one litre of diesel oil would translate into the following equivalent volume of gas, expressed in kWh:

1 litre of diesel oil = 10.1 kWh NCV diesel oil x (1 kWh GCV gas / 0.9 kWh NCV gas) = 11.2 kWh GCV gas = 1.02 Sm^3 of natural gas.

Consequently, if the diesel oil costs RMB 2.5/litre, then the market replacement value of natural gas in this case is RMB 2.45/Sm^3.

This consideration only reflects the price on the basis of equivalent useable energy content of the gas as compared to a competing fuel. The price of gas has to follow the price of the competing fuel based on the equivalency factors as derived above, to equalise costs based on the energy content.

To determine the replacement value in addition to the difference in energy content, the differences in maintenance and investment costs have to be considered.

For the simple purpose of illustration, let us assume a small building in a northern Chinese city with a gas distribution pipeline already in place. The building owner has a choice between heating his house with diesel oil or natural gas. Key economic data (indicative only) are the following:

Diesel Oil	*Natural Gas*
Boiler price: RMB 20,000	Boiler price: RMB 15,000
Radiator and pipes: RMB 5,000	Radiator and pipes: RMB 5,000
Oil storage tank: RMB 2,000	
Maintenance cost: RMB 800/year	Maintenance cost: RMB 500/y

Based on a technical life of 20 years for the two systems and an interest of 10% for the capital expenditures:

For the oil-fired system	*For the gas-fired system*
Annualised capital cost = RMB3,172	Annualised capital cost = RMB2,350
Yearly operational cost = RMB800	Yearly operational cost = RMB500
Total annual cost without fuel = RMB3,972	Total excluding fuel cost = RMB2,850

The difference of RMB1,122 per year is then a premium for the use of gas, so the consumer could pay more for gas compared to heating oil and still be not worse off economically, plus having the advantage of easy handling.

Assuming an annual gas consumption of 10,000 cm, the premium for gas over diesel oil would be RMB1,122/10,000 cm or about RMB0.1/cm. This means that if the diesel price is RMB2.5/litre, and the gas price based on energy equivalent terms is RMB2.45/cm, then the market replacement value of gas should be RMB2.55/cm.

In addition, account has to be taken of a number of other parameters such as differences in conversion efficiency, etc.

It should be noted that the above case is not based on real data and only serves the purpose of illustrating the method to calculate the market replacement value.

Net-back market-value pricing

The concept of net-back would calculate the average replacement value back to any point upstream of the final consumers in the gas chain, by deducting from the weighted average replacement value the costs (for distribution, load and quality management and transportation) necessary to bring the gas from the relevant point in the gas chain to the final consumers and to modify its load structure and quality according to the customer's need. Box 6.3 illustrates the net-back value at various points of the gas chain.

The following steps lead from the market replacement value concept to the net-back concept:

- Find the average market replacement value of natural gas in a particular market area by calculating the weighted average of the replacement value of the different sectors (usually: household and commercial, industry, power generation and gas as a raw material).
- Deduct the costs necessary to transform the gas as delivered at the point considered to the final market. Obviously the net-back value depends on the location and the condition of the gas at the delivery point considered. The closer the delivery point is to the final market and the more flexible the gas delivered, the higher the net-back value.

Box 6.3

The Net-back Market-Value Concept

The net-back market value of gas to a specific customer netted back to the city-gate, the well-head or LNG terminal is defined as follows:

Net-back	=	The average market replacement value of gas, determined by the delivered price, including taxes, of the cheapest alternative fuel to the customer (including any taxes on the alternative fuel) adjusted for any differences in efficiency, maintenance and investment, including the cost of meeting environmental standards/limits;
	minus	the costs incurred in the distribution sector to bring natural gas from the city gate to all consumers, taking into account storage and other load management costs;
	minus	taxes on the use/distribution of gas;
	=	Net-back value at the city gate (for the gas at delivery conditions)
	minus	the costs of transporting and storing the gas from the well-head or LNG terminal or import border to the city-gate;
	minus	taxes on the transportation and imports;
	=	Net-back value at the well-head, the LNG terminal or import border.

The net-back value is typically used as the basis for negotiation at any point in the gas chain that is upstream of the final customer; it may, however, also serve as a benchmark in cases of dispute.

In Continental Europe, the net-back market-value approach has traditionally been the basis of gas pricing throughout the gas chain. Such a system developed because of the need for the gas exporting companies to recover the large capital costs involved in building the pipeline infrastructure. By pricing gas through the chain in relation to competing fuels, sales in the market are maximised while the rent goes to the producers/transporters of the gas. The price risk and reward – which are linked to the movement of prices for competing fuels – are effectively transferred to the producer, who would get any economic rent available from the difference between the net-back value and the costs of exploration and production, and transportation of the gas to the delivery point. The risk pattern incurred by the gas producer is thereby similarly structured to the risk pattern in oil production, the main investment alternative for most gas-producing companies and governments.

The cost of gas production or LNG supply to the regasification terminal may in some cases be significantly lower than the net-back market value. As a result, there may be a considerable economic rent to be earned between the average net-back market value and the supply cost. In general, near-to-market producers have an inherent advantage because transportation costs are much lower. For example, producers in the Ordos Basin would enjoy higher well-head prices than producers in the Tarim Basin using this approach. Negotiations typically result in a sharing of the rent between the producer and the transmission and distribution companies. However, the part of the rent going to the producing companies depends on the upstream taxation of the producing country. As long as there is a rent available, the actors in the chain may think about special rebate schemes to foster additional gas sales.

The net-back pricing approach, based on free negotiations between the players along the gas chain, allows the distribution of the rent throughout the chain in a way that fosters the development of any part of the chain that could otherwise become a bottleneck. For example, selling gas to the end-user at a price clearly below the market replacement value may speed up market penetration and increase overall sales volume, leading to better economies of scale in production and transportation. Conversely, if there are bottlenecks upstream, charging the full replacement value to end-users may slow down the market penetration of gas, but would allocate more revenue to the upstream sector to invest in de-bottlenecking.

In principle, net-back pricing works with any set of competing fuels. The economic efficiency of net-back pricing, however, requires that the prices of competing fuels are market-based and undistorted. To the extent that differences in the environmental effects of different fuels are not already taken into account by defined emission standards, they might be taken into account by taxation. The effects of relative taxation will be dealt with later in this chapter. A severe restriction to the growth of the gas market in China is the availability of cheap coal in most end-use applications and often without stringent pollution control. To calculate the replacement value of gas *vis-à-vis* coal, all the costs related to coal storage and handling at the end-user level should be taken into account. The average net-back value of gas *vis-à-vis* coal is still low. Unless covered by emission and pollution standards, or even by a strict ban on coal use for polluted areas, it is hard for the replacement value to take into account the environmental damage (the negative externality) caused by coal-burning. In practice, governments can improve the competitiveness of gas *vis-à-vis* coal by using subsidies, or even better by charging different rates of tax reflecting the difference in externalities. Such policies would be justified by the environmental advantages of gas. Also, as energy security in relation to the increasing oil import dependency is a key concern, imposing an excise tax on oil products and thereby increasing the market replacement value of gas *vis à-vis* oil products would have the advantage of reducing oil consumption.

Deregulation of bulk gas prices in China, both at well-head and city-gate, as suggested below, would pave the way for the adoption of a market replacement/net-back pricing principle which allows for the development of a gas industry of optimal size. This in turn would encourage the production of natural gas in areas where the net-back value of gas is the highest relative to production costs, that is, close to consuming areas and close to existing pipelines.

GAS PRICING REGULATION

A key question that the Chinese authorities need to address is: to what extent, if any, is regulation of prices needed?

In any market economy, there are grounds for the public authorities to set prices only in cases of market failure, e.g. where market power stemming from a natural monopoly, which cannot be contested, is an issue. Where the supply of a good is competitive, it is most efficient to let the market determine the price. *Ex ante* price regulation (i.e. fixing the prices before the project starts) is against the principle of free markets and competition. It can only be justified in very specific cases, like cases of natural monopolies which cannot be contested. Moreover, regulation is potentially costly, both directly (with respect to the administrative burden) and indirectly through possible resultant market distortions, since regulation can never perfectly replicate efficient market outcomes. Consequently, governments usually seek ways of introducing competition into those parts of the industry where a competitive market can be established.

As will be further discussed in Chapter 11, it is clear that the Chinese gas industry is not in a position for gas-to-gas competition based on third-party access to make sense in the near term. But it is vital that gas compete freely and effectively with other fuels, primarily coal and oil, and that pipelines be built freely, subject only to health-safety-environment (HSE) regulation, but not to economic regulation. This will require the removal of price distortions in all fuel markets.

Why regulate gas prices?

An activity is a natural monopoly[9] when its subdivision would lead to higher unit cost (sub-additivity criterion). When looking at this criterion, the element of contestability must be considered. Short-distance transportation may fulfil the criterion of sub-additivity, but in view of the relatively small share of transportation costs in the overall value of gas, the disadvantage of foregoing economies of scale by building a second pipeline may not deter an investor. In addition, from an economic point of view the issue of building parallel pipelines should also be considered from a dynamic perspective. It may be much better for the development of competition to build sub-optimal parallel pipelines than to wait for lengthy regulatory processes. In any case, the possibility of building parallel pipelines is a very crucial element to make gas transportation competitive.

The natural monopoly characteristics of high-pressure gas transportation may differ from case to case. In a case like Canada, where huge volumes of gas are transported from the production sites in Alberta to the eastern parts of Canada and the US, the market size for transportation is a multiple of the maximum possible pipeline size, the conditions for a natural monopoly are not met.

Practically all grids have a natural monopoly character, as do gas distribution systems. In addition, they are usually based on using municipal property, namely the municipal streets, which requires a concession, which is often given as an exclusive concession, so that a legal monopoly comes on top of the natural monopoly.

In addition, exclusive rights over local distribution in the early stages of development of the industry are usually necessary to give confidence to potential investors that they will be able to recover their capital (Chapter 11). Where there is a single gas supplier to a particular end-user, regulating prices can prevent that supplier from charging excessively high tariffs.

9 The supply of a given commodity may be considered a natural monopoly where economies of scale are such that the unit cost of supply is lower with a single supplier than with multiple producers.

However, gas is always subject to competitive pressures from alternative fuels. Unlike electricity, gas can be replaced by other forms of energy in most uses, although the costs of permanent switching capacity may be high. Industrial consumers in particular may be able to switch to coal or heavy fuel oil relatively easily, as do power generators either by switching the input fuels or by optimising the use of power plants *via* the electric grid. In this case, the need for tariff regulation will be determined by the extent to which the gas company exploits its market power and makes abnormally high profits. Where the costs of gas supply are high, and the costs of switching to alternative fuels are relatively low, there may be very little scope for the gas supplier to extract monopoly rent or profits. In this case, the cost of regulation may outweigh any potential benefit, and it may be better to leave the gas company to negotiate prices freely with its customers.

China should deregulate well-head and bulk sales prices and introduce free negotiation of prices

The natural gas industry in China is at an early stage of development, and the potential for gas project developers to extract large rents, at least for the moment, is extremely limited. Large rents, if any, would help to speed up the development of the gas industry provided that they are reinvested in the sector. In any case, gas is subject to intense competition from alternative fuels. Consequently, there is no clear need for the government to continue to control prices at the well-head or at any point in the gas chain except for the protection of captive customers. The removal of price controls on gas sales and of any volume allocation scheme would permit project developers to negotiate prices along the supply chain according to the value of the gas in end-use markets, and the costs of supply on a project-by-project basis, and allow them to negotiate the distribution of rents in line with bottlenecks and risks. This would ensure that the prices negotiated take full account of load factors, since the project developers would negotiate prices primarily on the basis of peak annual capacity.

Abandoning price-setting would allow the government to focus on its appropriate role in creating a stable policy and regulatory regime, plus an incentive scheme *via* the taxation instrument. Such a regime should encourage the expedient development of the gas industry within the limits of economic rationality defined by the replacement value, bringing the highest penetration without negative opportunity costs of using gas instead of alternative fuels.

Pricing regulation for captive consumers

Most countries explicitly regulate the prices charged to small consumers, such as households and small commercial users, in order to protect these captive customers. Usually, the cost of switching fuels at short notice is very high[10] and, in most cases, it is not practical for small consumers to maintain dual-firing equipment or back-up fuel supplies. There is therefore a danger that a local distributor could raise prices to boost profits knowing that most customers

10 In most countries, there are explicit controls on the prices of bundled gas sales (the cost of the gas itself plus the cost of delivery). In Britain, where competition was extended to all customers, including households, in 1998, delivered gas prices are no longer regulated but national transmission and local distribution charges, which are included in delivered gas tariffs, continue to be regulated on a rate-of-return basis. Germany is the only country in Europe where there are no explicit regulatory controls on gas tariffs for small consumers, but national competition legislation prevents companies from exploiting market power and charging excessive prices. In addition, there is a multitude of local distributors owned by the municipal authorities, reducing the threat of monopoly abuse.

cannot switch to an alternative fuel. However, especially in a growing market, commercially-driven utilities will try to increase market penetration and therefore offer gas prices for new customers which are competitive compared to alternative fuels. As long as existing and new customers are being charged the same tariff, there is an in-built protection against existing customers being exploited on account of their sunk investment into gas equipment.

For captive customers, so long as they have a choice of fuels which can work as effective protection, they are no longer captive. In cases where gas is the only admissible fuel, regulated prices are necessary. From an overall economic point of view prices/tariffs to captive customers should be limited to the replacement value, with due consideration of possible premiums from environmental advantages, which are not easy to calculate. On the other hand, there seems to be no rationale to stay below such a price level as long as the gas sector can still be enlarged to bring its environmental advantages to more people. To achieve that, it should be ascertained – e.g. by taxation schemes – that extra revenue for the companies in the gas chain is invested in the development of the gas industry.

In China, tariff control should only apply to distribution companies that serve captive customers. The maximum tariffs that those companies should be allowed to charge should be set by the regulatory authorities taking into account the replacement value of supplying each customer category. But in designing the regulatory regime, the government should try to minimise administrative burdens on the management of the gas distributors and the overall cost of regulation.

TAXATION OF NATURAL GAS

The fiscal regime for natural gas production, transportation and sales has a major impact on incentives for investors to pursue gas supply projects and for consumers to switch to gas. In a system of free commercial decisions by many thousands, if not millions of participants, taxation, together with pricing, is one of the most efficient instruments to foster the development of a gas industry. If China's objective is to have 80 bcm by 2010, which means building up a gas industry comparable to Germany or the UK in about 10 years, then the tax system must be structured in a way to allow for such an unprecedented development of the industry.

The government will need to address a number of issues relating to gas taxation to improve the competitiveness of gas against other fuels, especially coal, and to make the overall regime more attractive to investors.

The present fiscal regime

According to a recent OECD study[11], China has a very low ratio of tax revenue over GDP by international standards, even compared to developing countries. Total tax revenue in 1997

11 OECD, 2002, "The current tax system and priorities for reform", Chapter 18 of the OECD report *China in the World Economy: The domestic policy challenges*, Paris, 813p.

amounted to 13% of the GDP, compared to 37.3% (27.7% excluding social security contributions) for OECD countries. Value-added tax (VAT) forms the largest fiscal source, as it accounts for more than 40% of the total tax revenue in China. VAT is generally levied at 17%, with a lower rate of 13% applying to basic subsistence goods, including gas.

Unlike OECD countries which have a consumption-type VAT system applying to all goods and most services, China has a production-type VAT system[12] under which taxes levied on the purchase of fixed assets cannot be credited against VAT charged for the sales of products produced by those assets. This type of VAT favours low-tech, labour-intensive industries and penalises high-tech capital-intensive industries such as the gas industry.

A reform of the Chinese tax system is due not only in view of its accession to the WTO (to eliminate certain discriminations between foreign and domestic investors), but also in view of the mismatch between tax revenues and the tasks ahead for China. Improving the transparency of the tax administration is also a big challenge.

The following gives an overview of the fiscal regimes applicable to gas activities along the gas chain in China:

Upstream exploration and production (E&P)

China's production-sharing agreements with foreign companies are in line with similar agreements in other non-OECD countries. A World Bank study ranks China in the middle range when it comes to the share of private companies in the revenue from oil or gas production. Apart from the provisions of production-sharing agreements, there are a number of separate taxes applied to upstream activities. The main taxes are:

- A resource tax on E&P activities (see below).
- A value-added tax, which varies depending on whether the company is onshore, offshore, domestic, or a foreign joint-venture:
  - CNOOC and onshore foreign-invested joint ventures are subjected to a 5% VAT tax based on their gross revenue.
  - Domestic companies operating onshore gas fields are subjected to a 13% production-type VAT rate.
- An income tax at 33% of profits, to be shared between central (30%) and local (3%) governments.
- Add-on taxes. All companies have to pay two local taxes: a municipal construction fee and an education cost fee, which together represent 10% of the VAT tax amount.

Resource taxes on E&P activities differ depending upon whether the company is domestic or foreign, operating onshore or offshore:

12 There are three types of VAT in the world: production-type, income-type and consumption-type. At present, most countries adopt the consumption-type VAT and apply it to all goods and most services. China adopted a production-type VAT in 1994, which applies to all industrial production, commercial sales, imports of goods, provision of processing services and industrial repairs and replacement.. According to the OECD, the Chinese VAT system was designed to suit the particular economic climate in 1993, in particular to bring down double-digit inflation by cutting capital investments. Today the rationale for that no longer exists and it is urgent that the Chinese government transform the VAT system into the consumption type.

- *Domestic onshore companies:*
    - Exploration and production licence fees. Both fees vary according to where the gas field is located. The exploration license fee amounts to between 100 and 500 RMB/km2, while the production license fee is 1000 RMB/km^2. Both license fees increase annually. As part of the Western regional development package and to encourage E&P activities in difficult areas, in June 2000, the Ministry of Land and Natural Resources and the Ministry of Finance jointly announced a range of measures for the reduction and exemption of these fees, under certain conditions and subject to approval.
    - Compensation fee. This fee is shared between the local and the central governments. It represents 1% of the sales income, without taking into account potential differences in the quality of resources.
    - A resource tax: This is based on the volume of natural gas sales and own-consumption. Each gas field enforces a different tax rate, from 2 to 13 RMB/1000cm. It is shared between central and local governments.
- *Offshore Domestic Companies and Onshore Foreign JV Companies:* CNOOC and onshore joint ventures with foreign companies operate under a different tax regime. They have to pay royalties of 0-12.5% based on annual production (see Table 6.7), and are exempted from paying any other tax. These royalties are collected by the central government.

Table 6.7

Natural Gas Royalties for Offshore Domestic Companies and Onshore Foreign JV Companies (% of output)

Annual production (bcm)	<0.1	0.1-0.2	0.2-0.3	0.3-0.4	0.4-0.6	0.6-1	1-1.5	1.5-2	>2
Royalty rate	0	1	2	3	4	6	8	10	12.5

Source: Provisional rules for the royalty payment of onshore oil and gas exploration activities by foreign JV companies, Chinese Ministry of Finance, 1990.

Gas transportation

Pipeline taxes include:

- A business tax at an average rate of 3.3%.
- An income tax at 33% of the profits.
- A customs tax on imported equipment or construction material.

LNG imports

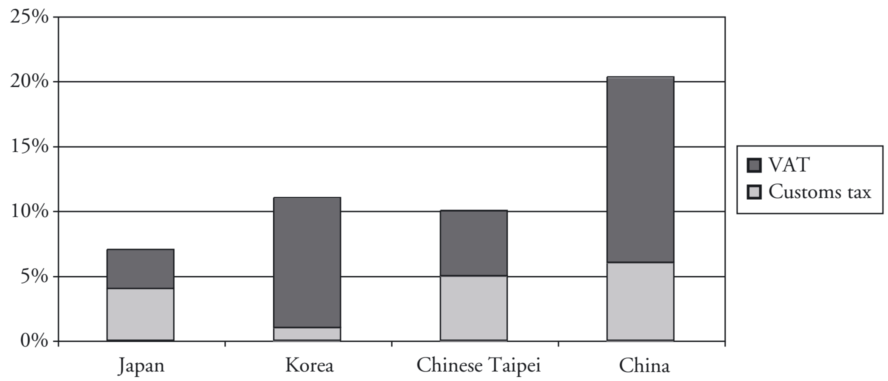
Taxes on LNG include:

- A customs tax of 6%.
- A VAT of 13%.
- Add-on charges which represent 10% of the VAT.

Figure 6.2 gives a comparison of the total amount of tax on LNG projects within the Asia-Pacific region.

Figure 6.2

Comparison of LNG Tax Rates among Selected Asia-Pacific Countries



Gas distribution

Local distribution companies are subject to the following taxes:

- 13% VAT.
- Sales tax plus various municipal taxes, which vary widely according to the city. In some cases, such as the Beijing Natural Gas Company, total taxes represent as much as 20% of the company's sales income.

The problems of the current gas taxation system

Apparently, it seems that the Chinese tax system is not overly onerous:

- a profit tax (the enterprise income tax) of 33% is not overly high in international comparison.
- VAT of 13% is within the international range.
- a royalty scheme of up to 12.5% without an additional petroleum revenue tax is more on the modest side.

The final assessment depends on the investors' share in gas profits, which varies from field to field. In any case that part – mostly defined in production-sharing contracts – is subject to international competition. International comparisons carried out by the World Bank also suggest that the average level of upstream taxes is neither particularly high nor low[13].

13 IESM, World Bank, *Workshop Summary: China Oil and Gas Sector Regulatory Reform,* PPIAF, 2000,.

However there exist important flaws in China's fiscal regime:

The first is related to the production-type VAT system that penalises investment in capital-intensive activities like the gas industry. It concerns all streams of the gas industry:

- In the upstream sector, production-type VAT adds unnecessarily to the costs of production. The average VAT volume for domestic producers is 9.6 % of total sales, which is substantial. In a system with administered prices this would be extra cost for the producer, which reduces the profitability of the investment. Even in a system of free competition it would be a cost risk taken by the companies, which under a consumption-type VAT system would be taken by the state.
- The midstream (transportation) is taxed by the business tax. There is no VAT on transportation services, but the pipeline company needs to pay VAT on the purchase of capital goods, and it is not clear how this VAT can be offset against the business tax.
- In the gas distribution sector, if the investment infrastructure is paid from the municipal budget, the disadvantage from production-type VAT may not be so significant. The point of paying VAT on investment which cannot be offset against VAT charged to the customers would, however, arise under private or public-private ownership of distribution companies.

Second, as pointed out by the World Bank[14], China's upstream fiscal regime both for oil and gas is regressive, i.e., the share of taxes in revenues increases as profitability declines. This is because of the application of resource taxes and VAT, both of which are based on gross revenues and do not take account of the underlying profitability. Under such a system, too little is taxed from the most profitable projects, while too much is levied on the least profitable ones. Taxing profits (*via* production-sharing agreements for example) is a better approach to encourage the development of marginal fields. The resource tax should also be linked to the quality of gas reserves.

A third problem is the current "exploration carry" regime in China, which reserves the option for the state to acquire up to 51% of equity in a project without any participation cost in exploration. This obliges the investor to cover 100% of exploration costs, bear 100% of the considerable risk and yet receive only 49% of the benefits in the event of success.

Fourth, the system implementation is unclear and allows local authorities to levy a large variety of fees. Over the past few years, local taxes, fees and charges have increased, as provincial or local governments try to benefit from increased natural gas production. These fees and charges were imposed at the discretion of local governments without any transparency.

Last, there are two different upstream tax regimes for domestic companies and for foreign-invested companies, which prevent fair competition and contravene the main principle of non-discrimination under the WTO regime. This will have to be removed in the coming years.

14 World Bank, IESM and PPIAF, 2000, *Workshop Summary: China Oil and Gas Sector Regulatory Reform*, Beijing, 14-15 December 2000, p. 82.

A main point of criticism of China's system of gas taxation would be that it is not designed to foster either the expedient development of a gas industry, or, more especially, the improvement of the competitive position of gas compared to less environmentally-friendly fuels.

FISCAL AND PRICE REFORM TO PROMOTE GAS MARKET DEVELOPMENT

Taxes are the main source of fiscal income, to be spent for the general functions of a state, e.g. to support education, defence, environment, health, judiciary system, administration etc., distributed between different levels of authority (central, regional, municipal) to enable them to fulfil their respective tasks. However, taxes may also serve as incentives or penalties to achieve a desired pattern of consumption, especially between substitutable products. They can be used as instruments to internalise externalities and to convert government policies into economic signals to the market. For example, if billions of dollars of the taxes collected have to be spent as part of the public budget on environmental clean-up, why not provide tax incentives for the use of environmentally cleaner fuels?

Fiscal policy can play a key role in stimulating the supply and demand for natural gas, especially in the early stages of industry development. Many countries have used favourable taxation of gas as a primary means of supporting market development (Box 6.4). Tax reform should complement moves to introduce market-based pricing of all forms of energy.

Box 6.4

Cases of Successful Promotion of a Rapid Development of a Gas Industry

The rapid penetration of gas in the energy balance, such as in Spain and Turkey, demonstrates the importance of price competitiveness. In both countries, lower taxes on gas sales than on competing fuel oil played a major role in making gas competitive against other fuels and stimulating rapid fuel switching (and also giving the sellers more revenue for investment):

- *Spain:* Gas consumption has increased rapidly since the 1970s, reaching 12% of total primary energy supply by 2000. Originally only LNG was consumed, but this is now supplemented by piped gas from Norway and Algeria. The Spanish government has promoted the uptake of natural gas in industry through explicit oil-related pricing and lower taxes on gas (no excise tax) than on oil products (e.g. an excise tax of 40% is levied for light fuel oil). Gas has been consistently much cheaper on a heat equivalent basis than gasoil, and broadly in line with heavy fuel oil prices in recent years. The non-price advantages of gas over fuel oil mean that gas is usually the preferred fuel when an oil or coal boiler is replaced, or for new boilers or direct heat applications.
- *Turkey:* Natural gas supply (by pipeline and LNG) began in 1992 and reached 16% of TPES in 2000. Gas to industry is priced in relation to heavy fuel oil and is taxed lower than oil products and coal.

In view of the urgent pollution problems in Chinese cities, and the potential benefits to be gained from developing a modern gas industry, it seems justified for China to use a favourable taxation regime in all parts of the gas industry and to increase taxation for competing fuels for a limited time, e.g. 10 years. After such time, the favourable regime could elapse – subject to a review of the extent of gas penetration, and subject to eventually using different instruments to foster the development of a gas industry. In the interim, there could also be a review to assess what additional instruments and measures might be necessary to achieve the gas penetration target.

Using taxes to encourage gas market development

Using taxes as an instrument to implement government policy by influencing commercial decisions by private actors is a valid instrument as long as the framework is clear and does not discriminate between the actors in the market and is not changed retroactively. This is especially justified if differences in taxes reflect differences in environmental externalities and costs.

Reducing all taxes on gas use and giving tax incentives to gas consumers for installing gas equipment can foster and expedite gas penetration. Different excise taxes on competing fuels are also a very powerful instrument to facilitate gas penetration: in many cases it proved much more powerful than any direct action by the government. Taxing fuel oil higher than gas, for example, would have the following effects:

- A dampening effect on consumption of fuel oil.
- More incentives to save oil and to invest in more efficient uses.
- A higher replacement value for gas if there is no (or a clearly lower) excise tax on gas.

It seems that the taxation of coal is politically difficult in China. Given its plentiful resources and China's capacity in handling it, coal will continue to play a crucial role in centralised power generation, where its environmental effects can best be controlled. It can eventually be used for more decentralised steam raising, e.g. based on PFBC (Pressurised Fluidised Bed Combustion). For other applications, coal will have severe disadvantages over gas. In the fight against pollution in the cities, strict emission standards or even a straightforward ban on the further use of coal (and heavy fuel oil) and the closing of existing coal applications may be most appropriate. That would leave the use of gas, diesel oil, LPG and electricity in polluted cities to meet the environmental legislation. It would also bring the urban energy structure into line with those of the US, UK, Japan and Germany – countries which have a strong share of coal but also modern gas-based manufacturing industries and heating systems.

Excluding coal from certain applications would result in competition only between gas and oil products, so the replacement value of gas would be increased by the excise taxation of oil products. These policy instruments would help create both the volume of demand and the additional revenues needed to build up a gas industry.

Tax incentives for re-investment in the gas industry

The other elements of the tax regime should work to foster re-investment into the expansion of the gas industry. This could be done by providing tax incentives for re-investing profits into the gas chain. Both for profit taxation and for rent-taking, the upstream tax regime should be structured in a way that favours additional investment into the gas industry. Accelerated depreciation would create incentives to invest, while deferring the take by the state, i.e. it is basically a free tax credit. The state could also choose to defer receiving its resource rent by releasing it, during the initial period, for the development of a sizeable gas industry. If rent-taking is too high at the beginning, development will be hindered in any case.

Taxes which are levied as a purely fiscal measure, like profit taxes, excise taxes or VAT, should be distinguished from fees, where the state or its regional or local authorities cede a part of state sovereignty by (even exclusive) concessions, or by ceding part of finite natural resources vested in the state. There is international competition to attract foreign investment into E&P; the Chinese government will have to regularly check if Chinese E&P conditions are still internationally competitive.

As described above, production-type VAT discourages investment in the gas industry and needs urgent reform. However, China should not wait until the tax system is reformed to remove the flaws of the present VAT system applied to the gas industry. Intermediary steps should be taken, such as an exemption from VAT of investment into the gas sector during the first phase of gas industry build-up. The negative effects of this VAT exemption on the total tax revenue of China could be compensated by the proposed excise tax on oil products.

It is also necessary to give the local and regional authorities involved a share of the present and future benefits of gas, as otherwise they would have no incentive for active co-operation. This might be better done by sharing a centrally levied tax, as this would reassure investors that no new taxes would be continually introduced.

Incentives for investment in gas distribution

In the distribution sector, concession fees, which are charged by a town for the use of the municipal streets, could also be structured in the most effective way to encourage investment. Such concessions are often given on an exclusive basis, but linked with a certain obligation to connect all customers according to defined criteria, with a minimum service standard and at standard or maximum prices.

If concession fees are construed as a local excise tax, i.e. a tax on the volume or value of consumption, it has the disadvantage of making the use of gas more costly than the use of competing fuels which are not subject to such a fee. Alternatively, concession fees can also be raised as an up-front lump sum, when a concession is auctioned against such a lump sum. In such a case, the respective local authority must refrain from asking for any concession fee during the lifetime of the concession. An advantage might be that on a per unit of energy basis, gas will be more competitive, provided that the concession fee be treated by the distribution company like an investment which has to be amortised over the lifetime of the concession. Provided enough investors compete for the concession, it offers at least a competitive yardstick of the revenue beyond cost recovery that can be expected from gas marketing.

In any case, when granting a concession for gas distribution, the market conditions must be clearly defined. They include, for example, any supply obligation, any exclusivity and any rules for the price-setting mechanism, and eventually how concession fees have to be paid.

Managing the transition

On gas taxation issues, there is a clear need for the country's energy policy institutions such as the SDPC to work with its fiscal authorities such as the State Administration of Taxation (SAT) to design a tax regime that would reflect China's energy policy objective. The reform of the taxation regime, as indicated by the above-mentioned OECD report, also concerns the gas industry. In particular, the gas industry could benefit if the government:

- Change production-type VAT to consumption-type tax (with an exemption of VAT for gas-related investment until the reform of the tax system becomes effective).
- Improve the co-ordination between the central government and provincial authorities in applying taxes, to avoid situations in which provincial tax policies undermine national policy goals by collecting taxes and fees.
- Remove any differences in tax treatment between domestic and foreign companies.
- Replace fees with profit based taxes; and
- Improve the transparency of the tax administration.

In addition, the government could take some specific measures to promote gas industry development. They include:

- Introduce an excise tax on fuel oil, but leave gas tax free.
- Consider exempting gas-related investment from all VAT.
- Restructure the upstream tax structure in favour of taxation of profits, to take into account local differences in geological and economic conditions.
- Periodically review upstream fiscal terms to ensure that they remain internationally competitive and are consistently applied to all industry participants.
- Consider reducing or removing the high taxes on imports of LNG, pipeline materials and equipment, which significantly raise the cost of building transmission lines and local distribution networks. The 6% tax on imports of LNG and the additional tax applied to the standard rate of VAT undermine the economics of LNG projects.
- Similar considerations would apply to concession fees. Concessions should be auctioned against a lump sum, with an incentive scheme in which part of the lump sum is paid back by the municipality to the concession holder if the latter reaches certain gas penetration benchmarks.

To implement the gas pricing and taxation reforms suggested in this report, the Chinese government should clearly set out a timetable (e.g. 5 years) to phase out the old system. This means abolishing the allocation of gas volumes by quotas and the administered prices at well-head and at city-gate, removing the flaws in the taxation system and establishing privately-owned gas distribution companies. New measures to promote gas use should be introduced, including the excise tax on fuel oils, ban of coal use in defined areas, exemption from VAT on gas-related investment within the gas industry until the VAT system is changed to a consumption type tax, low taxes for gas appliances and extra depreciation for downstream gas-related investment.

RECOMMENDATIONS

Based on the above analysis, the following recommendations are proposed:

RECOMMENDATIONS ON GAS PRICING AND TAXATION

The Chinese government should:

- Define a timetable for the transition of all gas prices and volumes to be freely agreed by market participants, subject to protection of captive customers and prevention of misuse of market power. Use taxation and standards as instruments to implement the government's gas policy.
- Encourage co-operation between its pricing and fiscal authorities and energy policy institutions to work out a pricing and taxation regime that would better reflect the energy policy objectives of the country.
- Remove – in a phased manner – all controls on gas prices at the well-head and city-gate, and to large end-users directly off high-pressure transmission pipelines. During the transition, ensure end-use competitiveness of gas by adopting a net-back pricing methodology, based on the market replacement value, to gradually replace the current cost-plus formula.
- Co-ordinate the timetable for phasing out price controls with other policy actions such as the commercialisation of distribution grids, the further privatisation of state-owned companies and a stronger involvement of private investors in the gas industry.
- Implement a comprehensive reform of the fiscal regime for natural gas as suggested in the preceding section, to lower the overall burden of taxation on gas supply, and improve the market position of gas relative to other fuels, especially coal, to reflect its environmental advantages and to stimulate switching to gas.
- Reflect the relative environmental benefits of gas through an excise tax on competing fuels. If that is not politically possible for coal, then for polluted areas no new coal-fired equipment should be installed, and old coal-fired equipment should be phased out.
- Boost investments into all parts of the gas chain, by exempting gas-related investment from VAT (in anticipation of a VAT reform). Consider tax credits, e.g. by extra depreciation for gas-related investment.
- Regularly review the structure and management of upstream taxation to ensure international competitiveness of E&P for gas in China.

ISSUES SURROUNDING LONG-DISTANCE GAS PIPELINES

Highlights:

- *Building a long-distance pipeline is an important challenge in all parts of the world. It is particularly so in an emerging gas market such as China. Two of the main preconditions are a sufficiently large paying demand and adequate gas reserves. Once these preconditions are met, the most critical success factors are the alignment of the interests of all the major players and a well-balanced risk-reward allocation among the players.*
- *The key short-term issue for the West-East Pipeline is timely and effective downstream gas market development. But long-terms issues, such as the implications of the pipeline's commercial structure for the future gas industry and the introduction of competition in both the upstream and downstream sectors, need particular attention.*
- *Beyond purely domestic long-distance pipelines, China will be involved in building cross-border gas pipelines and will possibly be acting as a transit country for such pipelines. The implementation of these projects will require both the Chinese government and the companies involved to abide by international rules on cross-border energy investments and transit.*

This chapter discusses the key issues in building and operating long-distance pipelines in China and the additional complications related to pipeline imports. By long-distance pipelines, we mean pipelines that run across several thousand kilometres.

LONG-DISTANCE GAS PIPELINES IN OR INVOLVING CHINA

As shown in Table 2.2, China has completed a number of gas pipelines in recent years and is now building the 4,000 km West-East Gas Pipeline (WEP). The WEP is by far the longest pipeline built in the country and will be among the longest in the world. It is likely that other long-distance pipelines will be built in the future (Table 7.1), mostly of cross-border nature. Some hold good medium-term prospects, such as the one that would connect Kovykta gas field in Russia's East Siberia to China and Korea, others are for a much more distant future.

Table 7.1

Possible Future Long-Distance Pipelines Involving China

Route	Approx. Length	Possible Annual Throughput
Kovytka-Ulan Bator-Beijing-Rizhao	3,365 km	26 bcm
Kovykta-Changchun-Shenyang-Bohai Bay-Korea	4,520 km	30 bcm
Sakhalin- Harbin-Shenyang	2,500 km	12 bcm
Yakutsk-Changchun-Beijing-Qiangdao-Seoul-Kitayushu	4,800 km	20 bcm
Turkmenistan-Uzbekistan-Kazakhstan-Xinjiang-Shanghai	6,100 km	30 bcm
West Siberia-Mongolia-Shanghai	6,500 km	30-38 bcm
Yakutsk-Kovitka-Harbin-Beijing and Dalian- Korea	5,626 km (land only)	30 bcm
Yakutsk and Kovitka combined-Harbin-Beijing and Dalian- Korea	4,961 km (land only)	30 bcm

Source: Quan & Paik, 1998; APERC, 2000; Northeast Asian Gas & Pipeline Forum, September 2000. ERI/SDPC, 2000.

Not all proposed pipelines will be built. However, the successful completion of these pipelines, or as is more likely just a few of them, would lay the necessary infrastructure for increased gas use in China. They would also become the central part of the envisaged Northeast Asia Gas Pipeline Network. But many obstacles will have to be overcome for these projects to materialise.

STAGES IN BUILDING A GAS PIPELINE

Pipeline transportation is one of the two methods of moving natural gas from the production base to consuming areas[1]. The rationale for building any gas pipeline is that there are gas reserves at one end and gas demand at the other. The development of a new gas pipeline includes several stages that need to be carried out successfully: market analysis, technical and financial feasibility studies, regulatory approvals; financing; physical construction; pipeline operation and management.

- *Market analysis and feasibility study*: Market analysis usually forms part of the feasibility study of the project. It will address crucial issues including: Are there sufficient reserves and demand for natural gas to make the pipeline an economic venture? What is the paying/bankable demand of end-users? What are the parameters of the pipeline design that will best serve demand, i.e. in the most economic way (see Box 7.1)? The most important parameter is not the potential of demand, but the pace at which this potential can be transformed into actual paying demand, keeping in mind that since gas may have to compete with other energies its demand level can vary with its price competitiveness. An assessment of the technical feasibility and the costs of alternative pipeline routes will have

1 The other method is *via* ocean-going LNG cargo. Both ways of transporting gas have different features and also different economics. In many cases there is no choice, e.g. for land-locked gas, pipeline transportation is the only option. Also in many cases of gas finds close to the shore but separated from main markets by deep oceans, LNG will be the only technically feasible option. There are some cases where both options are technically feasible at the same time.

to be made. An optimal way of financing will also have to be sought as part of the economic evaluation of the pipeline.

Box 7. 1

Design of Gas Pipelines

There are many issues in the design of the pipeline and the planning of its route. The following components are crucial in the design phase:

- Basic capacity for which the investment is supported by a realistic development of paying demand.
- Distribution of demand along the pipeline.
- Location, type, and size of storage facilities.
- Diameter and pressure of pipe, distance between compressor stations, with possibly different pipeline parameters for different sections of the pipe (e.g. due to different transportation volumes along the pipeline due to *en route* demand or supply).
- A route that crosses near or through areas where markets are expected to develop.
- Flexibility to expand the capacity of the pipeline to serve additional demand. This is mainly determined by the number and siting of compressor stations and by the possibility to upgrade transportation capacity by adding compressor stations.

Pipelines have very significant economics of scale that can be exploited at the planning stage (costs are roughly proportionate to diameter, while transportation capacity is roughly proportional to the 2.5th power of the diameter). They are often designed and built to enable future increases in capacity as demand expands. After the pipeline has been laid, capacity can be increased through additional compression and through pipeline looping[2]. There is a difficult trade-off between pre-investing in the capacity of a pipeline by over-dimensioning the diameter, and the restriction and costs of later measures to increase capacity. For a new project, especially for a large diameter pipeline project, the level of demand is usually low at the beginning and will increase in line with demand build-up.

Pipeline capacity must be designed to meet peak demand (unless peak demand can be balanced by storage or other peak shaving facilities), which can be several times larger than demand at off-peak periods.

- *Regulatory approvals*: If the market analysis proves positive, then the promoters will seek approval from regulatory authorities with regard to routing and its health-safety-environmental (HSE) impacts. This can be a lengthy process, as they need to obtain permits, right-of-way, perform any required environmental assessments, and meet all health and safety requirements.

2 Looping refers to laying an additional pipeline alongside and connected to the existing pipeline.

- *Financing*: Obtaining financing for the pipeline is a particularly challenging task.
- *Physical construction*: Only when all regulatory permits are obtained and other conditions are met can promoters start the physical construction of the pipeline. Promoters may need to build access roads and clear construction pathways and finally to dig and explode pipe ditches, lay the pipeline, build river crossings, build compressor stations, pipeline interconnections, and receipt and delivery metering points. After the completion of the pipeline, promoters will be required to restore the construction site along the pipeline.
- *Operation and management*: During the operating phase, the operator must ensure an efficient capacity utilisation, infrastructure security and operational safety (e.g. no gas leakage from the pipeline). This usually needs sophisticated monitoring and control systems, such as the System Control and Data Acquisition (SCADA)[3].

GENERAL CONDITIONS FOR LONG-DISTANCE GAS PIPELINES

The building of long-distance pipelines involves an investment of billions of dollars over a very long timeframe. Consequently it requires a number of specific conditions. Having gas reserves at one end and market at the other is a necessary but not a sufficient condition for an economically viable pipeline. The most important criterion is the commerciality of the pipeline project, that is, the assurance that the project is viable commercially with a reasonable rate of return for investors, which adequately compensates for the risks taken. This requires that certain additional conditions be fulfilled:

A sufficiently large base of paying demand

The most important prerequisite for building a long-distance pipeline is a sufficiently large demand, either at the end or along the route, that can absorb the huge amount of transported gas and pay for it at a price that would yield the required level of return on investment for the gas pipeline and gas production. The pipeline will not be viable if the market is not big enough, if consumers are not able to pay for the gas at market-based price, if the demand volume is not high enough, or the price competitiveness of gas is low.

Slow market development can jeopardise the economics of the pipeline project. It is therefore essential that, right from the beginning, marketing efforts be conducted to ensure sufficient demand and an expedient build-up of demand for gas. If the market presents a slow build-up compared to the envisaged capacity of the pipeline, it may be wise to consider a step-by-step approach for building the pipeline by either having a lower diameter of the pipeline and adding compression as demand increases, or by starting with those segments that are closer to the market, provided there are *en-route* sources of gas which can provide early deliveries.

3 It has become common practice to lay fibre optical cables along with the pipeline. As these cables are needed for the SCADA system, and their data transmission capacity is much larger than what is needed for the SCADA system, the spare capacity can be used as a main information highway.

A sufficient level of reserves

The existence of sufficient gas reserves is also a necessary condition for investing in a new pipeline project. To make large pipelines economically viable, which may need amortisation periods of 20 years or more, a firm supply base, in terms of proven gas reserves equivalent to at least 20 years of the contracted volume of gas consumption, must be proven before the investment decision is taken.

Risk sharing and mitigation mechanisms

Long-distance gas pipelines present specific risks (Box 7.2) which, if not appropriately addressed, would jeopardise the viability of the project (given that transportation costs represent a large share of the value of the gas for long-distance pipelines). All investors therefore look for ways to cover or mitigate those risks. Risk identification, analysis and mitigation mechanisms are key to successfully assuring the financing of the project. A better assessment of risks will help to spread them more evenly, e.g. by allocating the risks to those players who are in the best position to manage them (e.g. risks linked to construction to the construction companies by turnkey contracts, marketing risks to the companies marketing the gas, e.g. by take-or-pay contracts, political risks by corresponding guarantees by the government, etc.) This in turn will reduce the overall risks of the project and the cost of the risk premium for financing the project. Linked to risk identification, a further challenge is to categorise the issues and obstacles in such a way as to determine where corrective intervention is appropriate – whether for governments or for industry participants.

Box 7.2

Risks Specific to Long-Distance Gas Pipelines

The specific risks of long-distance pipelines stem from the combination of two factors: *i)* investment is not only high up front, but is also irreversibly tied to a specific project once the pipeline is laid; *ii)* transportation costs make up a large share of the market value of the gas. In addition to the general risks in energy sector or other large investments such as cost-overrun or construction delay, investment in long-distance gas pipelines entails a number of specific risks*:*

- *Commercial risks*: They include risks related to market demand and price competitiveness.
- *Demand risks*: Long-distance pipelines transport large volumes of gas. The pipeline capacity is designed to meet an estimated demand at a particular time. There is a risk that the demand is lower than expected or the demand build-up is slower than expected, which could negatively affect the pipeline economics. In addition, and unlike other industrial investments including oil, the demand served by the pipeline is usually linked to a specific region and shortfalls in demand in that region cannot easily be compensated by demand from other areas.

- *Price risks*: Gas can be replaced by other fuels, so there is always a risk that projected demand will not materialise if the gas is not competitive. However, the clean burning properties of gas relative to other fuels and the related lower externalities of gas might be properly reflected by taxation or other regulatory measures.
- *Political and regulatory risks*: As a pipeline is a fixed investment which is sunk the moment it is constructed, its viability becomes very vulnerable to interventions into its technical and economic performance by political authorities. This risk is multiplied when a long-distance pipeline crosses country borders or states/provinces within a country, as this will involve more actors in the decision-making and regulatory process. At each stage where a pipeline crosses a country's border, it needs to comply with that country's regulatory requirements and is therefore exposed to intervention by the respective authorities, which could not only jeopardise the technical or economic performance of the respective section, but also that of the whole project.
- *Foreign exchange risks:* In a gas pipeline project, the investor's money is tied irreversibly to the country and to the market served by the pipeline, entailing a risk of currency exchange and repatriation of earnings and profit.
- *Technical and security risks*: long-distance pipelines often run through remote areas and terrain that could be very difficult for construction and supervision (high mountains, rivers and lakes, etc.). The longer the pipeline, the more it is exposed to security problems, and measures to ensure operational security will be necessary.

A facilitating investment regime

Investment in long-distance pipelines constitutes a decision to commit the investor's resources to the project over a very long term (30 years or more). It needs an appropriate legal, regulatory and fiscal framework in the project country, which is stable, transparent and non-discriminatory, in order to protect investors' interest with fair taxation and a fair rate of return on investment, and mechanisms to resolve any resulting dispute in a neutral way. A number of organisations, such as the APEC Forum, have provided recommendations on the construction of gas infrastructure (Box 7.3). The Energy Charter Treaty provides rules for the appropriate investment framework, which are accepted by its signatory states. It also provides a neutral conflict resolution mechanism between investors and the host country for an energy project, which boosts investor confidence (see below).

In an emerging gas market, reducing investors' risk is essential. This may well call – initially – for not imposing third-party access (TPA) on a pipeline and may even go as far as limiting competition for a defined timespan, such as exclusive concessions for the supply of gas to non-industrial/non-power consumers in defined concession areas. A scheme called "open season" seems to be useful to ensure competition while making use of economies of scale in the planning stage of a pipeline. Under such a scheme, the intention to build a pipeline is made public and other players may participate in a joint venture or by booking long-term capacity. If the scheme is successful, there may only be a small or no capacity left open for later TPA.

At a later stage, facilitating access to a wider range of market participants can encourage market efficiency and expansion. A "sunset" provision on the initial exclusive rights may therefore be helpful from the outset to signal that a transition to greater competition is envisaged in due course. From the outset, pipeline investors should be aware of the timing of the introduction of TPA, so that they can take it into account in their project assessment.

Box 7.3

APEC Recommendations to Facilitate the Construction of Natural Gas Infrastructure in the APEC Region

- Permit recovery of and return on investment in natural gas infrastructure projects.
- Establish transparent and non-discriminatory procedures for obtaining licenses/authorisations to construct and operate natural gas infrastructure projects.
- Establish transparent and non-discriminatory procedures for project sponsors to obtain appropriate eminent domain (expropriation of land), siting and right-of-way approvals.
- Establish health and safety standards for the construction and operation of natural gas infrastructure consistent with highest international standards.
- Ensure that insurance required to facilitate financing can be met in a timely and cost-effective manner.
- Clarify the environmental standards, appropriate to the conditions of the project, applicable to gas infrastructure projects and enforce such standards on a non-discriminatory basis.

Source: "Recommendations Concerning Accelerating Investment in Natural Gas Supplies, Infrastructure and Trading Networks in the APEC Region", endorsed by the APEC Energy Ministers at their third Meeting, held in Okinawa, Japan, in October 1998.

Other issues

In addition to the general conditions described above, there are other critical issues to be addressed before a long-distance pipeline project can begin. They include health, safety, and environmental impact assessment, and the corresponding measures to mitigate those impacts. These issues are very critical to the long-term interests of all investors. The ability to efficiently and economically procure rights-of-way, other permits, materials, and skilled labour is equally important in the investment decision. Since the transportation of gas is highly capital-intensive with a long payback period, the choice of robust partners, with financial, commercial and technical skills, is also crucial.

All over the world, many proposed gas pipelines, most of which made good economic sense, did not materialise due to the failure to meet the general conditions listed above. Table 7.2 provides a list of gas pipeline projects in North America that were proposed but never built, due to economic/commercial or regulatory reasons.

Table 7.2

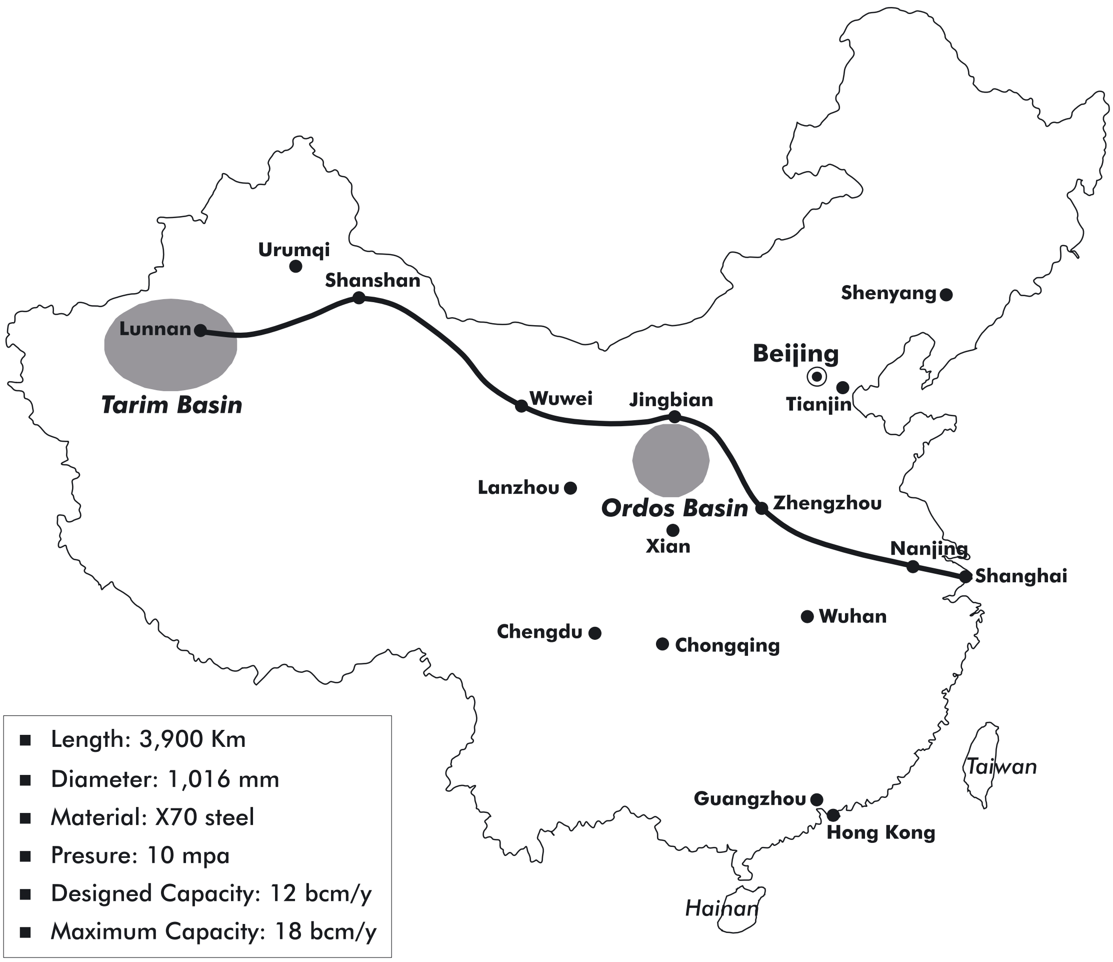
Examples of Natural Gas Pipelines that Failed to Materialise in North America

Name	Description	Reasons for failure
Alaska Natural Gas Transportation System	The project, proposed in 1980, was to build an overland pipeline from Prudhoe Bay in Alaska through Canada to the US Midwest	• Projected natural gas price forecasts did not support the capital costs. • Companies determined that the timing was premature to drawdown the oil reservoir pressure, so the gas was more valuable for re-injection to maintain pressure. • Price and availability of alternative US supply. • Financing not completed.
Northern Natural Gas Pipeline	The project, proposed in 1970, was to build an overland pipeline from reserves in Alberta in Canada to the US Midwest	• Rejected by US Federal Power Commission and Canadian National Energy Board. • Insufficient supply of contracted natural gas. • Transportation rates too high. • Opposition of competitor
Yukon Pacific Pipeline and LNG Project	The project, proposed in 1987, was to build an overland pipeline from Prudhoe Bay in Alaska to Cook Inlet and then ship gas to Japan in the form of LNG	• Lack of demand in Japan.

Source: Adjusted from Lynn Coleman, "Financing, Management and Pricing of the Cross-Border Gas Pipeline Projects in North America", Presentation at the US-China Oil and Gas Industry Forum, 11-12 September 2001.

Figure 7.1

The West-East Gas Pipeline



Description

Officially announced in March 2000 as one of the key infrastructure projects for the "Western Regional Development" campaign, the West-East Pipeline (WEP) project obtained the approval of China's State Council in February 2002. Immediately afterwards, the SDPC gave the green light for PetroChina, the main sponsor of the project, to start construction work on those segments of the pipeline that need more time to complete, such as river-crossing and wetland sections. Construction of the whole line started on 4th July 2002, when PetroChina and partners signed the framework agreement in Beijing.

The pipeline

The pipeline is designed to transport natural gas from the Tarim basin in Xinjiang and the Ordos basin in Shaanxi to consumer areas in east China including Shanghai and the Yangtse Delta region for a period of 30 years at 12 bcm/y (see Figure 7.1). The total length of the trunkline is 3,900 km[4], running through desert (the Gobi desert), crossing several high mountains, and three large rivers (the Yellow River, the Hui River and the Yangtse River). It also involves a number of branch pipelines along the trunkline.

The trunkline consists of two sections: the east section (1,458 km) links Shanghai with Jingbian, where gas from the Ordos basin will be piped into the trunkline; and the west section (2,432 km) will link Jingbian with Lunan in the Tarim basin. The designed capacity for the first phase is 12 bcm/y, to be supported by 18 compressor stations along the trunkline. Maximum capacity is 18 bcm/y, which will require the building of 10 more compressor stations. An underground storage capacity of 1.5 bcm is also planned for construction near demand centres using depleted oil and gas wells. PetroChina plans to complete the east segment by early 2004 and the west segment by 2005.

Cost

The whole scheme is projected by the SDPC to cost RMB146.3 billion (US$17.6 billion), divided between upstream development (RMB28.4 billion), pipeline construction (RMB49.1 billion), and downstream market development (RMB68.8 billion).

Partnership

On December 29, 2001, PetroChina and a Shell-led consortium, which includes Russia's Gazprom and Stroytransgaz and the Hong Kong based Hong Kong & China Gas, signed a non-binding "Interim Agreement in View of Providing Basis for a Framework Agreement on the Joint Operation of the West-East Gas Pipeline". Key elements of the interim agreement are the following:

- The upstream gas exploration and production part will adopt a production-sharing contract (PSC) model; a co-operative joint-venture will be set up to oversee the pipeline operation; and an equity joint-venture will be formed to operate a unified gas sales company.
- The Chinese party will take 55% in each shareholding in the pipeline JV and the PSCs of the fields in the Tarim basin that supply gas to the pipeline. The remaining 45% go to the Shell-led consortium, which is allowed to be freely split among its members.
- The term for both the pipeline JV and the gas sales company will be 45 years.
- Definition of the commercial operation model for the gas sales company.
- Agreement to take into account each party's standards and regulations with respect to health, safety, environmental and social impacts, while strictly complying with the relevant Chinese laws.

4 The initial estimate of the pipeline length was 4,167km. Further route design through remote sensing, terrain inspection and bypass have reportedly reduced it to 3,900km in the agreed design by project sponsors.

Later, SINOPEC – China's largest downstream oil company – decided to join the venture. The Huston-based Exxon Mobil and its partner – Hong Kong China Light and Power – also joined the foreign consortium. All partners in the project signed the framework agreement in Beijing's Great Hall of the People on the 4th July 2002, the day when the construction of the pipeline was scheduled to start officially. The final split for the upstream PSC and pipeline joint venture was the following:

- PetroChina: 50%
- SINOPEC: 5%
- Shell and Hong Kong China Gas: 15%
- Gazprom and Stroytransgaz: 15%
- Exxon Mobil and Hong Kong China Light and Power: 15%.

It was reported that the partners will finance 35% of the pipeline construction cost by equity contributions and the rest by commercial loans. The structure of the gas sales company is being discussed at the time of writing of this report.

Gas reserves

The WEP will be supplied by production from two basins – the Ordos basin and the Tarim basin. According to PetroChina, the Changqing area of the Ordos basin, where Jingbian is located, has been identified by the government's National Reserve Committee to hold a proven geological reserve[5] of 750 bcm by the end of 2001, which is the largest in China. The main gas supply source will be the Tarim basin's Kuche-Tabei area. The area is certified by the National Reserve Committee to hold a proven geological gas reserve of 527 bcm, of which 372 bcm is recoverable (end of 2001 estimate)[6]. The area is composed of one large gas field (Kala-2, discovered in March 2000, with a proven gas reserve of 250 bcm) and six medium-sized ones, with a possible total annual production capacity of 15 bcm.

The government is confident that there are enough gas reserves to supply the pipeline for 30 years at 12 bcm/y. If there is not enough from the Tarim basin, other sources such as imports from West Siberia and Central Asia could be envisaged, but the key question is the cost of this imported gas.

Consumer market

The main market for the WEP is in the east China region, with one city and four provinces with the following data on population and GDP in 1999:

- Shanghai city: 14.7 million people, US$49 billion GDP;
- Jiangsu province: 74 million people, US$93 billion GDP;
- Zhejiang province: 45 million people, US$65 billion GDP;
- Anhui province: 62 million people, US$35 billion GDP; and
- Henan province: 94 million people, US$55 billion GDP.

5 See Chapter 2 for the difference between the Chinese and western notions of proven reserves.

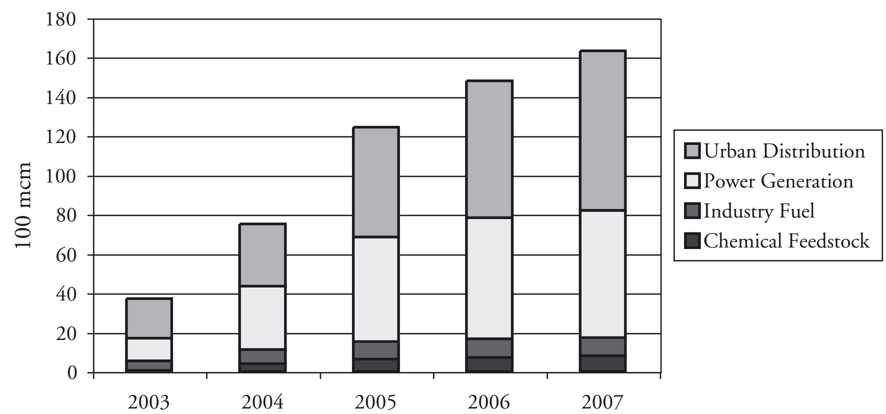
6 According to the SDPC, the Tarim basin has three main gas-bearing areas (Kuche-Tabei, Bachu and Taxi) that account for 54% of the basin's total gas resources (estimated at 8.3 tcm).

The SDPC expects the total gas demand in this region to grow from 3.1 bcm in 2003 to 10.5 bcm by 2005 and 20.8 bcm by 2010.

By end 2001, PetroChina had signed letters of intent on gas supply with 45 gas off-takers (32 local distribution companies and 13 direct-supply large consumers) in the above-mentioned market region. The total intended gas consumption volume by these off-takers is shown in Figure 7.2. At a speech given by PetroChina's Chairman in February 2002, the aggregate demand level was revised to 0.8 bcm in 2003, 8.3 bcm in 2005 and 12.3 bcm in 2008. And the numbers keep changing. As these letters of intent are not legally binding, PetroChina and its partners plan to work in order to sign "take-or-pay" contracts with the intended gas off-takers.

Figure 7.2

Expected Demand Build-Up for the West-East Pipeline Gas in East China



Source: PetroChina, Communication to the IEA Experts Mission, November 2001.

Pricing

In February 2002, the SDPC announced that the average city-gate price of natural gas from the WEP will be RMB1.29/cm, with RMB0.45/cm for upstream and RMB0.84/cm for transmission and storage. City-gate prices differ according to cities/provinces: RMB1.35/cm for Shanghai, RMB1.37 for Zhejiang, RMB 1.31 for Jiangsu, RMB1.24 for Anhui and RMB1.16/cm for Henan. The announced prices are tax-inclusive, but it is not clear under what quality terms (heat value, pressure and temperature, etc.) the gas will be delivered. They are based on the assumption that gas supply volume reaches the designed capacity of 12 bcm/y by 2007. According to PetroChina, the project can generate profits when the annual sales volume reaches 8.6 bcm/y, or 72% of the designed capacity.

Critical issues in the West-East Pipeline

As the largest oil and gas sector investment project in China, the WEP represents a number of risks that need to be shared or mitigated by all, public sector and private investors alike. A project of this scale necessarily faces a number of important challenges that need to be tackled along the way. The issues that need to be addressed are not only short-term issues related to the pipeline construction, it is also important to take the longer-term issues into account at this stage. They concern the structure of the project and its position in China's natural gas system in the future, the ability of the project to deal with any possible change of circumstances, as well as the need for introducing competition in the future.

Short-term project issues

The most important short-term issue is the development of the gas-users market downstream.

Downstream market build-up

The West-East Pipeline is one of the symbols of China's supply-push strategy to develop the gas market. It needs to take particular care on other important issues that have been raised in Chapter 3, including a clear pro-gas policy in view of its environmental advantages, proactive marketing, synchronisation of investments, development of anchor projects and realistic timing.

Assuming that the pipeline itself can be completed without any serious technical difficulties and that a sound financial arrangement is found, the most important risk factor is the downstream demand build-up. The potential for gas demand is undoubtedly there in east China, but what counts in the end is transforming this potential, through active marketing, into the actual or legally committed off-take volume by end-users, or the payment from off-takers under "take-or-pay" contracts. This involves both off-take risk and market risk, which are analysed in Chapter 9.

"Take-or-pay" contracts between the gas marketing companies and local distribution companies and large direct users are highly desirable to mitigate the off-take risk. Those contracts may be difficult to conclude for the following reasons:

- Large gas-fired power plants, which can be a stable large gas consumer (e.g. a 500 MW base-load plant taking more than 500 million cm/year), can sign "take-or-pay" contracts with gas marketers only when they are backed by a corresponding power sales contract with the power grid companies or by opportunities to sell power on their own. Gas-fired base-load power generation faces a number of problems as presented in Chapter 4, most critically the competitiveness of gas *vis-à-vis* coal. Base-load gas-fired plants also need to reconcile with base-load electricity from the "West-East Power Transmission Programme", especially from the Three Gorges Dam. The uncertainty about the future of the power supply structure of the country also poses problems.
- Petrochemical plants using gas as feedstock will face severe competition both domestically and internationally. None of them will have a firm and guaranteed product outlet market, which will lead them to be reluctant to commit themselves under a take-or-pay contract for feedstock supply. They are also particularly sensitive to the proposed gas price. If there is free competition, it will be difficult for chemical plants in east China that use WEP gas to compete with those at the well-heads of gas rich countries such as Malaysia and Indonesia.

- At present, local distribution companies are in general loss-making. In addition, they will need a huge amount of investment to develop their market and to carry out the conversion from manufactured gas to natural gas, which will require considerable time and effort (Chapter 5). As their customers are all relatively small users, whose demand volume has not yet been totally ascertained, they will also face difficulties in committing themselves with a cash payment over a long-term contract.

Gas pricing is a key parameter in negotiations with gas off-takers. It should be left to the market players, rather than government, to decide on pricing. The creditworthiness of industrial off-takers and the lack of marketing skills and efforts of distribution companies may present a serious problem for the financing of the pipeline project.

An additional area of concern is the current requirement for any large project to go through the approval process by various levels of authorities[7]. Large gas-using projects often fall into the category of large projects (above RMB100 million of capital expenditure) which require the approval of the State Council. If the approval process is very long, it will significantly affect the rate of downstream demand build-up.

Closely related to the downstream demand build-up is the timing of investment in various parts of the gas chain. If too much emphasis is put on the physical construction of the trunkline, with not enough attention being paid to upstream development, branch line construction, and gas consuming projects in the downstream, the economics of the whole project may be jeopardised. The feasibility of the project has to include the potential investment mismatch in its sensitivity analysis. Close attention should be paid to investments outside the trunkline.

One possible way to avoid the mistakes of the Jingbian-Beijing pipeline would be to delay for a limited number of years the construction of the west section of the WEP. This would allow more time for market development *via* the east section with gas from the Ordos basin, which is sufficient to supply the market in east China for many initial years. But this runs contrary to the political objective of the pipeline and is not what has been agreed with the international consortium. Consequently, the government needs to pay particularly close attention to the link between pipeline construction and downstream market development and take corresponding action.

Project management

The pipeline project may face problems of construction delay and budget over-expenditure compared to the planning. Causes may include under-estimation of the difficulties in digging through mountains and crossing large rivers, or delays in procuring materials and getting right-of-way. Though some risks could be shared through an appropriate contractual structure, such as turnkey contracts with construction companies, they need to be fully assessed in the

7 Current regulations in China require approval by the provincial planning commission for any new project with investment below RMB 30 million; by the SDPC for new projects between RMB 30-100 million; and by the State Council under the SDPC's recommendations for any new projects above RMB 100 million. The approval route shifts to the SETC when it concerns renovation or expansion projects, but the investment threshold remains the same. It is reported that the government is in the process of reforming this project approval process, with more authority delegated to local administration and project sponsors.

overall planning and co-ordination of the project. Good project management will be the key. However, these are standard risks linked with large projects and the companies involved should be able to manage them successfully.

A very important issue related to project management is to minimise the health-safety-environmental (HSE) impacts by taking preventive or reparative measures. The awareness of these issues is generally lower in Chinese companies compared to their Western counterparts. But complying with the most stringent regulations is not only in the interest of the country and its people but also in that of investors.

Operational issues: safe and efficient operation

Once the pipeline is completed and goes into operation, special care needs to be taken to ensure the safety of its operation (see Box 7.4).

Box 7.4

Safe Operation of Long-Distance Pipelines

Long-distance gas pipelines require continuous monitoring and control as well as periodic inspections to maintain public safety and to ensure reliable operations. When natural gas pipelines are buried underground, as is the case for most pipelines everywhere, damage by unauthorised digging or excavation is the leading cause of pipeline accidents. When damage does occur, procedures for handling such damage, e.g. stopping the gas flow and making prompt repairs, need to be in place so that endangerment of public safety and the potential for supply interruptions are minimised.

A main concern is the protection of the pipeline against corrosion. Various methods are applicable, but cathodical protection seems to be standard. The integrity of the pipe wall can be monitored from the inside by the use of pigs with mechanical means or ultra sound (know as smart pigs).

There are measures to monitor the pipeline's integrity from the outside and to prevent negative impacts on the pipeline by human activities.

- A traditional way which still seems to have its merits is inspection of the pipeline route in relatively short intervals – e.g. every few weeks – by persons going along the pipeline route to make sure no human activity – like illegal building – is interfering with the pipeline's integrity or to monitor the impact of any natural events like storms or plants growing into the pipeline.
- Aerial Patrols – Fly-overs conducted at least twice a year in residential areas to identify areas of concern such as unauthorised digging and environmental changes.
- Pipeline Markers – Markers placed along the right-of-way to alert the public to the presence of the pipeline.

- Leak Detection Surveys – Surveys of the right-of-way by operations personnel using equipment that detects leaks.
- One Call Programme – Telephone numbers for people to call before they begin any excavation activities near pipelines in order to obtain information about the location of pipelines.

Furthermore, by a SCADA system, the control room should be able to monitor and control the main operational parameters of the pipeline like pressure and chemical composition of the gas along the line, and status of the compressor stations, etc.

Operational issues: reliable supply/storage

Another important operational issue is to ensure the gas supply reliability to downstream customers, both to deal with possible supply disruption either from upstream production or pipeline incidents, and to deal with demand fluctuations. Some short term – mainly daily – fluctuations can be dealt with by measures at the distribution sector. Variations of large volume and longer duration require an adequate level of gas storage.

There are several mechanisms to balance gas supply and demand for a specific time or period of time. Some of these mechanisms are supply tools that can vary the volume of gas made available by the system, and others include demand tools that vary the call on gas[8]. Buffer tools, such as underground gas storage, also play an essential role in balancing supply and demand by the pipeline transmission company.

This leads to the need for building gas storage systems (Box 7.5). Those storage systems are owned by pipeline companies, and costs are appropriately reflected in the transmission tariffs. But pipeline companies need to co-operate with LDCs on the use of storage for operational balancing of the system supply.

8 See more details on these tools in the forthcoming IEA publication on *Flexibility in Natural Gas Supply and Demand*, 2002 (forthcoming).

Box 7.5

The Role of Natural Gas Storage in Long-Distance Pipeline Operations

Gas storage is a vital part of the natural gas industry as it ensures supply reliability during periods of heavy demand by supplementing capacity on long-distance natural gas pipelines and serving as back-up supply in case of an interruption in well-head production or pipeline accident. Historically, the main role of storage in production has been to smooth natural gas production between the peak and off-peak demand seasons by supplying places to store gas in the summer, when gas consumption is low in major residential and commercial consuming regions. In the gas-producing areas, storage facilities are used primarily to balance flows on transmission lines during the winter. Storage also allows load balancing of daily throughput levels on long-distance pipelines, which is necessary to ensure smooth operation of the pipeline system. This enables pipelines to operate more efficiently because they can function at a more constant level throughout the year, thus making better use of available pipeline capacity.

The most efficient means to store gas is by underground storage, which can be regarded as a transfer of natural gas from the reservoir of discovery to other reservoirs, usually closer to market areas. There are three principal types of underground storage that are used in the world today:

- **Depleted Fields:** They are usually depleted natural gas or oil fields located close to consumption centres. Conversion of a field from production to storage duty takes advantage of existing wells, gathering systems, and pipeline connections. The geology and producing characteristics of a depleted field are well known. Depleted fields also contain native gas, the gas that remains after economic production ceases and before conversion to use as a storage site.
- **Aquifers:** An aquifer storage site is a water-only reservoir conditioned to hold natural gas. Such sites are usually used as storage reservoirs only when depleted gas or oil reservoirs are not available. They are generally more expensive to develop and require longer conditioning time, which is about twice as long as for an average depleted gas or oil field.
- **Salt Formations:** There are two basic types of salt formations used to store natural gas: domes and beds. Salt domes are very thick salt formations. A salt bed storage site is generally developed from a much thinner salt formation located at shallower depths. Salt formations are the most expensive of the three types of storage facilities to develop and maintain.

Abandoned mines and specially mined cavities constitute two other marginal types of underground storage. In addition to these underground storage facilities, there are other means for load balancing at the distribution level, such as *in situ* LNG, spherical tanks and line-pack. These means are discussed in Chapter 5.

Dealing with long-term issues

The most important long-term issue for any long-distance pipeline project is the alignment of interests of all involved parties in a balanced and stable way. This would cut the risks of obsolescent bargaining (Box 7.6) at its root. Parties involved in the project include not only the project sponsor of the pipeline and its major joint venture partners, but also upstream companies, local gas distributors and final gas users, and local and central governments.

It should be noted that long-term "take-or-pay" contracts (see Box 3.1) have proven to be a good instrument to deal with marketing risks and to ensure the minimum cash flow needed for gas infrastructure investments, especially in cases where the gas market lacks liquidity, but they are not an end *per se*.

Project risks change over time. Contractual structure thus needs to appropriately reflect the risk-reward balance for each party at different stages of the project. The overall risks are normally high during the initial construction period and in the first years of commercial operation. Once the project is completed, all the risks linked to the construction phase will be over, so the remaining risks are mainly those linked to gas market development or caused by government intervention. While market risks can be mitigated through long-term take-or-pay contracts, political risks can be covered either by the legal system of the country, *via* membership in the Energy Charter Treaty, or by specific agreements of the country with the investor, such as host-government agreements. World Bank guarantees with a counter guarantee by the country to the WB is another way to cover the political risks.

As the WEP involves a commercial agreement of 45 years, its structure should be designed in such a way that it is able to cope with changes in circumstances which are likely to occur in one way or another during the project's lifetime, like changes in economic circumstances, be they domestic or international. Changes in political circumstances should only give the right to the investor to change the contract; governments should be bound by preceding decisions. There should be no incentive for governments not to honour the agreements they entered into.

To a large extent, China's natural gas policy seems to be linked to the development of the WEP project. Indeed, some sources indicate that the WEP is a type of pilot project for other gas infrastructure facilities. This would seem to ignore the fact that the WEP is a rather unique project and that, in consequence, it would be difficult for the government to apply the same type of policies to other projects.

From the structural point of view, the current commercial arrangement, with JV companies formed by the same partners to conduct all upstream, midstream and downstream activities, may not be conducive to upstream diversification and downstream competition Those issues will be discussed in more detail in Chapter 11.

On the regulatory side, there is a need for an agreement between the government and principal project sponsors on a timetable for future mandatory open access to the pipeline, with a sunset clause for initial exclusive rights. This may appear to be necessary, especially for the east section of the pipeline. Such a timetable would provide a kind of roadmap for all sponsors and therefore reduce the uncertainties. An agreement like this could also provide a case for the elaboration of a more rigorous legal framework that governs gas transportation and distribution activities.

In summary, it can be said that the WEP project lays an important foundation for gas infrastructure development in China and, in recognition of this role, the government has already announced a number of special policies. However, much more can be done to manage the risks of the pipeline and to improve its economics. In particular, the government should:

- Step up efforts in downstream market development by defining a clear pro-gas policy and by reducing the burden in downstream gas project approval procedures.
- Strengthen the link between the construction of the west section of the pipeline and downstream gas market development.
- Recognise the project's unique set of characteristics in generalising the application of policies and measures to other gas infrastructure projects.
- Encourage the alignment of interests between upstream and downstream players between the project's domestic and international participants, and provide a policy and legal framework that can help the stability of such alignments. The government itself should keep out of commercial decisions and negotiations.
- Pay attention to long-term structure and regulatory issues in defining the framework conditions for this particular project and make sure that short-term project decisions do not jeopardise the long-term goals of gas market development.
- Liberalise price control at wholesale level (both at well-head and city-gate) and encourage net-back gas pricing (both are necessary conditions for take-or-pay contracts).
- Set clear and stable fiscal rules (taxes and concession fees) over the project's lifetime, by taking due consideration of the risk-reward balance at different stages of the project.

Beyond the WEP project, the government should set clear and efficient regulations, especially technical standards and assessment of safety, health, environmental and social impacts, for building any new pipeline. It should provide efficient co-ordination between the branches of the administration that are involved, both vertically (central state, local states, municipalities) and horizontally (various departments and ministries: e.g. economics, finance, environmental affairs, health and safety, labour, municipal affairs, etc.).

ISSUES ON PIPELINE GAS IMPORTS AND TRANSIT

In the future, China is bound to become a gas importing country and probably also a transit country for a number of cross-border pipelines (see Table 7.1). Many projects have been discussed and routes drawn up in the past. They include the following:

Russia's east Siberia and far east

In 1994, CNPC signed an agreement with SIDANCO, a Russian gas company, for the construction of a long-distance pipeline for the supply of 20 bcm/year of piped gas from East Siberia (Kovykta field plus possibly from Sakha Republic) across Mongolia to China. The two sides reconfirmed the agreement in 1996 and a three-year feasibility study was commissioned. In March 2000, the feasibility study was submitted to both governments. It was reported that the pipeline export project from Irkutsk to China and then to Korea with an annual capacity of 30 bcm would cost US$6 billion. The construction is divided into two phases: the first, to be completed around 2005-2007, to supply mainly north-east China, and the second phase to supply one third of the gas to South Korea. China's decision to build the West-East Gas Pipeline in 2000 has postponed this option until a future date.

Another possibility of gas pipeline import is from Sakhalin Island, but there has been no serious study so far.

Turkmenistan

Also in 1994, China signed an agreement with Turkmenistan for a gas pipeline that would bring 10 to 20 bcm/y to China and Japan. The proposed pipeline is 6,700 km long and must go through Uzbekistan and Kazakhstan before reaching China's Xinjiang autonomous region. The initial feasibility study – conducted jointly by China, Japan and Turkmenistan – showed that the pipeline itself would cost US$12 billion to build. Given the poor economics and the risks of political instability in the region, Japan has abandoned this option and the whole project is suspended indefinitely.

Russia's west Siberia

In 1997, CNPC concluded a broad agreement with Gazprom for a massive supply of west Siberian gas to China and further to Korea and possibly to Japan. Gazprom proposed a special route that would link Tomsk in the south of west Siberia through the Altai mountains to Urumqi, and finally to Beijing and the Yellow Sea Ports.

Kazakhstan

In Kazakhstan, China's CNPC outbid its Western competitors and won two oil fields in 1997. The deal required CNPC to invest US$9.5 billion over the next 20 years, including the construction of a 3,000 km oil pipeline from western Kazakhstan to Xinjiang, at a cost of US$3.5 billion. The project is on hold for the moment as CNPC has shifted its interest towards Russia. The Asia-Pacific Energy Research Centre (APERC) has included a scenario for a supply of 32 bcm/y of natural gas by pipeline from Kazakhstan to Shanghai[9], but in reality there is no firm plan for any gas pipeline from that country.

Among the above options, the east Siberian one seems to be the most promising.

The east Siberia option

Gas reserves

In Russia's east Siberia (mainly Irkutsk Oblast and Krasnoyarsk Krai) and far east (including Sakha Republic and Sakhalin Island), a considerable number of natural gas fields have been

9 APERC, 2000. *Natural Gas Infrastructure Development in Northeast Asia: Costs and Benefits.*

discovered one after another since the 1970s. Only a few of them are currently producing gas, solely for the use of local industries. At present, together they account for only 8 bcm/y, or 1.35% of total Russian gas production (584 tcm in 2000). But in terms of recoverable reserves (proven + probable), this part of Russia has a total of 3.8 tcm and accounted for 8% of the country's total reserves of 46.9 tcm in January 2001. Table 7.3 provides a summary of gas reserves in these areas. If hypothetical and possible reserves were added, the amount would be much higher. The potentiality appraisal survey conducted by Japan National Oil Company estimates all classes of reserves (gas resources) to be 27.5 tcm. Further drillings are necessary to confirm the size of the reserves.

Table 7.3

Natural Gas Reserves in Russia's East Siberia and Far East (as of January 2001)

Area	Gas Reserves (in bcm as of 1st January 2001, including A+B+C1 of Russian gas reserve classification)
Krasnoyarsk region without Evenkiysk	103
Evenkiysk AD	251
Irkutsk region	1,278
Taimyr AD	282
Sakha Republic	1,218
Sakhalin	657
Total	3,789

Source: IEA adjusted from Russian government sources.

Unlike west Siberia, the gas fields and related infrastructures in the east of Siberia and Russia's far east have not been developed at all. This is partly because of their remoteness from markets. A huge amount of investment would be required for the development of the fields and pipeline systems, which might make the development of the gas uneconomic under present circumstances. The region has been left behind in economic development for long time.

Kovykta, in Irkutsk, was the first gas field to be discovered in 1975. According to the Russian Academy of Science, confirmed reserves of the Kovykta gas field amount to about 1 tcm, the largest field in east Siberia and far eastern Russia. Kovykta is thus the only economically viable gas field to be developed as a single project. This is why the industry consortium of Russia, China and South Korea has been conducting the feasibility study for the Kovykta gas field and pipeline. Other fields need to be developed, together with neighbouring fields linked by a pipeline system.

In Russia's far east, gas resources are mainly located in the Sakha Republic and Sakhalin Island. Gas fields in the Sakha Republic are also estimated to have abundant reserves, but natural conditions are harder and the fields are dispersed over a vast region. Development costs, therefore, would be higher than the development of Kovykta gas field in Irkutsk region. Almost all the Sakha region is covered by permafrost and becomes marshland in summer. The Sakhalin 1 and Sakhalin 2 PSA have substantial gas reserves that are adequate to support LNG or pipeline projects to Japan, China and perhaps also Korea.

The Russian Academy of Science projects that gas production in east Siberia (including Sakha Republic and Sakhalin) will increase rapidly from 2010 starting with Kovikta field (see Table 7.4).

Table 7.4

Natural Gas Production Projection for East Siberia and Far East (in bcm/y)

	1995	2000	2005	2010	2020
Production	8	8.1	10	52	99
Demand	8	7.95	9.6	16	33
Export	–	–	–	36	66

Source: Siberian Branch of Russian Academy of Science, Irkutsk, 2001.

Gas demand

The key to the development of the gas reserves in east Siberia and Russia's far east is to develop gas consumption markets. These include local gas consumption within the Russian border, China's Northeast region, South Korea and Japan. South Korea and Japan are well developed gas markets, which are essentially supplied by LNG. Additional supply *via* pipeline would enhance the energy security in both countries. However, the Japanese market is rather stagnant for the time being. In South Korea, the Ministry of Commerce and Industry projects that by 2010 the Korean market will require a piped gas supply of 10 bcm/y.

Local gas demand in east Siberia until 2010 is low, because of the region's small number of inhabitants and slow rate of economic growth. At present, no gas pipeline systems or gas market exist in east Siberia. The east end of the Russian pipeline system stops at Nobokuznek and Noboshibirsk, which are at the south-east end of west Siberia. Despite the growing concern about SO_2 emissions, east Siberia is one of the largest coal production regions, and there is no clear sign of new investment to switch the coal-burning industry structure to gas-fired systems. The start up of export-dedicated gas projects may stimulate local demand, but the total demand volume will be limited.

Hence the major market is China's north-east and Bohai Bay regions, which consumed around 5 bcm of gas in 1998. China's SDPC estimates that these two regions can absorb 20 bcm/y of natural gas supply from Russia. But the market has not yet been developed in these regions and there are serious questions about the ability of natural gas to compete with the regions' cheap domestic coal. Overall, it appears that for any east Siberian pipeline project to materialise there is a need to have a much stronger demand base, which can only be found in South Korea.

Prospects on east Siberian pipeline options

Among the various pipeline proposals (see Table 7.1), the following two routes have the best chance of being realised:

- Kovykta gas field – Manzhouli – Shenyang – Bohai Bay – South Korea
- Kovykta gas field – Mongolia – Beijing – Shandong Province – South Korea

The first route is considered as the most probable route by the concerned parties, but related issues have not yet been resolved. It is China's preferred option. It has the advantage of providing the north-east China region, which is highly polluted, with a clean source of energy. It can also use the existing pipeline routes that were built for oil transportation. But as the demand centre is more in the southern part of that region, the construction cost will be higher than the second option of transiting through Mongolia. The second option is also under study.

Following the submission in March 2000 of the feasibility study by Russia and China, an industry consortium from Russia, China and Korea decided to undertake a joint initial feasibility study (IFS). The study was scheduled for completion by the end of March 2002, but completion was postponed to the end of 2002 or early 2003. Key issues under consideration include pipeline route, gas price and gas demand.

The pipeline routing will significantly affect the total costs. It has been reported that construction costs for the first route, with a distance of about 4,520 km, are estimated to reach $10.7 billion and that the second option, 3,113 km in length, would cost about $8 billion. According to one feasibility study, which was based on the assumption of a 56 inch diameter pipeline with 20 years supply contract, the costs of gas transportation to China's north-east coast for these two routes are estimated to be US$1.99 and US$1.48 per thousand cubic feet (which is more or less equal to one MBTU) respectively. According to Rusia Petroleum, production cost of the Kovykta gas field would be US$0.76 per thousand cubic feet. Thus, if the transportation and gas production costs are combined, the price of Kobykta gas ranges from US$2.24 to US$2.75/MBTU (or RMB0.66 to 0.81/cm). This price range would be very competitive compared with the LNG and West-East Pipeline gas project, which is set at RMB1.35/cm.

The Chinese position on the gas route has not yet been decided, but seems to favour the Manchurian (Manzhouli) route to avoid the complication that would be caused by transit fee negotiations with Mongolia. It is said that China has learned from the dispute between Russia and Ukraine. China also proposed that Russia combine the two gas fields of Kovykta and Yakutsk to secure the long-term supply with two options for combination on the Russian side (see Figure 7.3). If this proposal is accepted, the route may be constructed in two phases, with the first phase linking Kovykta to Dalian and Beijing and the second phase extending the pipeline to Yakutsk at one end and to Korea at the other. China and Russia have also been discussing the possibility of building an oil pipeline of 2,240 km (1,450 km within Russia and 790 km within China) from Angarsk in Irkutsk region to Daqing in north-east China. The oil pipeline would bring 20 million tonnes of oil per year by 2005, increasing to 30 million tonnes by 2010 for a period of twenty years. If the oil pipeline goes ahead, there will certainly be some advantages to building a parallel gas pipeline following the same route.

Figure 7.3

China's Proposed Routes for Kovykta and Yakutsk Gas Imports

Source: SDPC

There are two options for the pipeline to go from China to Korea, either *via* North Korea or a sub-sea route by the Bohai Sea. South Korea's position concerning the pipeline route seems to have been intentionally left open for future political decision. KOGAS, the concerned party of the Initial Feasibility Study in Korea, retains the two options for the pipeline route. One is Kovykta-Manchuria-Shenyang-Bohai Bay-South Korea, and the other is through North Korea. South Korea considers that the North Korean option is a highly political issue. There is uncertainty whether North Korea would wish to receive natural gas supplies as an off-taker or simply demand the transition fee. The industry side of South Korea thinks the North Korean route would just contribute to increase gas transit costs and other problems and thus it would be wise to avoid such third-party involvement in the routing issue.

The key Russian partner is Rusia Petroleum. It is a consortium formed by BP (25%) and other Russian partners with the leading stake held by Russia's Tyumen Oil Co. (TNK). Rusia Petroleum holds the license for Kovykta gas development and has historically been the negotiating party of the Russian side. The most recent focus of negotiation with the Chinese party, the national CNPC, has been on the gas price. It has recently been disclosed that the findings of China's study on gas pricing have disappointed Rusia Petroleum's shareholders. TNK proposed the international gas price to the CNPC at the border, but the Chinese side offered a much lower price. This price negotiation has slowed the process.

The Chinese side has also demanded from the Russian government a clarification of the role it envisages for Gazprom in Kovykta. In 2001, Gazprom was formally appointed by the Russian government as the co-ordinator of all the Russian east Siberian gas development. This implies that Gazprom now represents the Russian gas upstream companies in feasibility study negotiations with China (CNPC) and South Korea (KOGAS) as well as in all the aspects of possible future negotiations related to Kovykta gas field and Sakha Republic.

For Korea, there would be no doubt that the Russian piped gas option would be well suited for the diversification policy of the Korean government, but this option would depend on the economics and future negotiations with Russia and China. Korea seems to have no strong position on the route passing through Mongolia.

Another possible gas export project in the 2010 horizon concerns Sakhalin. Export options include pipelines to north-east China and to Japan (Sakhalin I) and LNG for China, Japan and Korea (Sakhalin II). However, much remains to be decided in terms of whether the gas will be moved by pipeline or as LNG, whether each project will build its own infrastructure or share joint facilities, and where the markets and buyers for the gas are.

Russia's Energy Strategy, published in November 2000, foresees gas exports from Kovykta starting by 2010, while Sakhalin gas exports would either be underway by then or start shortly thereafter. The Strategy also suggests that exports from the Sakha Republic could start as early as 2010, but this is by no means certain even in 2020. The year 2010 seems a highly optimistic target for the commencement of any export project other than Sakhalin LNG and pipeline supplies.

Specific issues for cross-border gas pipelines

Physically, building a cross-border gas pipeline is like building two gas pipelines in different countries at the same time. Commercially and operationally, it is more complicated. A cross-border pipeline involves international energy trade, and if it passes through a third country, issues of transit also have to be resolved. Pipeline projects must be submitted to regulatory review simultaneously in all the countries involved. The regulatory risks will be reduced if the technical and HSE regulatory framework and procedures are predictable and reasonably efficient in all countries involved. A clear economic regulatory framework that is stable over time will also enable project sponsors to make their investment decisions based on a reasonable assessment of the commercial merits of a project.

A cross-border pipeline involves more players than a domestic project. They include:

- the country owning the gas resources,
- the company(ies) contracted for the exploration and production of gas,
- the transit country, the transit company,
- the consuming country,
- the purchasing company in the consuming country,
- the transport company and distribution companies in the consuming country, and
- the final customers.

When more than one sovereign state is involved, there is a need for all these states to share the risks and rents. Alignment of interest of all parties is the key. This needs to be done in a way that ensures a well-balanced allocation of risks/returns for all players.

Cross-border pipeline projects depend on the committed participation of multiple parties over a long period. In a cross-border pipeline project, some risks may be amplified by the fact that the interests of several sovereign states are at stake. In particular, there is a risk of so-called "obsolescent bargaining" (Box 7.6).

Box 7.6

Avoiding Obsolescent Bargaining by a Well Balanced Alignment of Interests

Obsolescent bargaining refers to a situation where the original agreement between the parties becomes obsolescent as one or more parties—often sovereign states or state companies—seek to improve their position once the pipeline is built.

To avoid this happening, it is essential that the interests of all parties be aligned in a balanced and stable way over the long-term and that no single party should perceive itself as being a loser in the deal. This perception of fairness is either with respect to its vital interests, to the alternatives available to the proposed deal, or *vis-à-vis* other parties of the deal. In other words, there must be alignment of all stakeholder interests. Balance of interest means that the agreement is transparent to all stakeholders, provides reasonable profits according to the risks, and shares the project rents in a way that takes into account the alternatives and strategic position of the parties with neutral reference points. Stability means that there should be clear rules in the initial agreement for changes and for conflict resolution.

In addition, there should be a clear set of incentives to respect the agreement, or penalties for changes with credible threats. Credible alternatives to the pipeline, either through fuel substitution or through other gas supplies are other important means of prevention.

The company structure of a cross-border pipeline project may take different forms. In North America, the typical structure is a limited partnership pipeline company in each country, and the two companies are not engaged in partnership or joint venture with each other across the border. A "Pipeline Interconnection and Joint Operation Agreement", signed by the two companies, governs the integrated operation of the pipeline. Transportation tariff methodology could be different between the countries.

In the European Union, a pipeline gas-import project often involves companies from different importing countries. Participating in the building and operation of the pipeline is usually part of a gas import deal under a long-term minimum-pay contract. The company structure would typically consist of a separate joint venture company for each country the pipeline touches, formed by the companies involved in the projects as buyers, and in more recent cases also involving the sellers[10]. The companies decide their shares in different sections depending on the importance of the corresponding section for each of them.

An interesting example of a successful cross-border gas pipeline project, which could be used as a reference for the Russia-China pipelines, is the Bolivia-Brazil pipeline (Box 7.7).

Box 7.7

The Bolivia-Brazil Gas Pipeline

The Bolivia-Brazil Gas Pipeline (BBGP) links Santa Cruz in Bolivia to Porto-Alegre in Brazil. It is a 3,150 km pipeline including two sections. The first section, 1,970 km in length, runs from Santa Cruz to Campinas in Brazil. It started commercial operations on 1 July 1999. The second section, 1,180 km in length, extends from Campinas to Porto Alegre on Brazil's southern coast. It started operations in March 2000. The pipeline is expected to reach its full capacity of 30 million cubic meters per day (or 11 bcm per year) by 2004. The project cost was estimated at US$2 billion.

The project started with a 20-year gas sales agreement signed between Bolivia's Yacimentos Petroliferos Fiscales Boliviano (YPFB) and Brazil's Petrobras in 1993. The initial supply would be 8 mcm/d, and volume would increase linearly over the first eight years of the contract to a plateau level of 16 mcm/d. In March 2000, the two sides signed a second agreement to increase gas exports to 30 mcm/d to meet future market demand in Brazil.

The project faced a number of challenges. Among the most important ones were market and regulatory risks. The share of gas in the Brazilian energy mix was particularly low (3%) and gas distribution companies did not exist. Brazil and Bolivia had a tradition of non-economic fuel pricing and non-transparent government regulation. The gas reserves in Bolivia were considered insufficient to cover the export project during its full life. As public funds were not available for the project, the major challenge was to find private sponsors for a project presenting such risks.

10 A special case so far is the Interconnector between the UK and continental Europe, which was conceived as an open season pipeline. The investment was made by 9 companies. The economics of the joint venture project were secured by gas 'ship or pay' agreements, originally by the joint venture partners or some of their subsidiaries.

Several important factors enabled the completion of the project. They include:

- Alignment of interests: For Bolivia, it was critical to find a new outlet for its gas production as its contract with Argentina was expiring. For Brazil, it was very important to diversify energy supplies and adopt a more environmentally-friendly source of energy.
- Strong support of Petrobras (pushed by the Brazilian government): Petrobras accepted to bear most of the risk on both sides of the border. When financing problems appeared on the Bolivian side, Petrobras agreed, first to arrange financing for the Bolivian section with repayment from the waiver of future transportation fees, and second, to pre-purchase 6 mcm/day of uncommitted upside transportation capacity on both sides of the border.
- "Delivery-or-pay" contract by YPFB that takes the supply risk when the reserve base was considered as insufficient.
- Active participation of international energy companies including BHP Petroleum, El Paso Energy, Shell, Exxon and British Gas[11].
- New legislation and pricing policies: to remove the regulatory and price obstacles on the market side, Brazil adopted new legislation in favour of foreign investors and ended the Petrobras monopoly. The constitutional amendment in 1995 removed major legal barriers for private investment in Brazil's oil and gas sector. Brazil also adopted the Hydrocarbon Law in 1997, which included the principle of fair access to downstream markets and market-based pricing. Petrobras and the distribution companies agreed on a gas pricing scheme which ensured that natural gas could compete on the market.
- Commitment by international financial institutions, and especially the World Bank: in 1997, when the project was still blocked by many uncertainties, the World Bank decided to appraise the project and concluded that it was economically feasible and was the best of several alternative options. The Bank then agreed to provide a direct loan, which also helped to obtain additional financing.

Source: Removing Obstacles to Cross-Border Oil and Gas Pipeline. World Bank, 2002 (forthcoming)

Role of government in cross-border projects

Governments have an essential role to play in cross-border projects. They are crucial stakeholders in any successful gas cross-border project. Their role and responsibilities need to be clearly defined, however. Not all factors (risks) should be in the government's domain, but some critical factors do need government involvement. On 26-27 March 2002, the IEA held a major conference on cross-border gas trade, providing an opportunity to share experience on most of the major

11 These companies participate in both sections of the pipeline with the following ownership structure: Petrobras has a 51% interest in the Brazilian portion of the line, in partnership with BHP Petroleum/British Gas/El Paso Energy (25%), Shell/Exxon/Transredes (20%) and other private investors (4%). The Bolivian part of the line is operated by Transredes, a joint venture between Enron, Shell and Bolivian pension funds (51%), in partnership with Bolt JV, a joint venture between Shell and Enron (34%), Petrobas (9%) and BHP/British Gas/El Passo (6%).

projects worldwide, and to discuss best practices. Its main conclusions on the role of governments in cross-border gas projects are as follows:

- Governments play an essential role in facilitating cross-border gas projects, even in the context of the growing importance of the private sector. They can facilitate understanding between sellers, buyers and transit countries, through regional co-operation frameworks or regional fora.
- Governments' major responsibility is to establish a clear, transparent and predictable framework for private (domestic and foreign) investments within their country. This would allow market participants (project sponsors, investors) to confidently invest in and develop cross-border natural gas projects. Governments can reduce the risks that are associated with large cross-border projects, in particular those that are of a political, legal or regulatory nature (Box 7.8).
- Governments also need to ensure that investors are not taxed twice (e.g. *via* double taxation agreements) between countries, even though cross-border trade does not require harmonisation of regulation or similar degrees of market liberalisation on each side of the border.
- They also have to establish a clear and transparent institutional and regulatory framework for technical and economic issues for gas production, trade and transport, and consumption. In countries where a fully operational legal framework is not yet developed, governments need to consider including alternative mechanisms in their policies, such as giving individual assurances to investors to facilitate the construction of the cross-border project.
- A clearly defined energy policy is a key factor for the development of any gas project. Governments may have to assume part of the risks, especially in the initial phase of a project.

In a word, wholehearted government support through a clear energy and gas policy is a precondition for trans-border gas projects. Support should also include concrete measures like the acceptance of international investment and transit protection rules.

Box 7.8

Role of Government in Mitigating Risks on Cross-Border Gas Pipelines

Governments have a special role to play in mitigating some of the specific risks related to cross-border gas pipelines, in particular risks of a political, legal or regulatory nature, for which they may be responsible.

- **Political risks:** War, civil war, and tensions in the region are risks which the respective governments of the region can try to ease. The government is particularly responsible for poor governance, threat of expropriation and can give guarantees for its own behaviour. This latter type of political risk can be mitigated by credible commitments and credible mechanisms to compensate for losses due to political interference (e.g., acceptance of international arbitration for dispute resolution).

- **Legal risks:** Risks of abrogation/non performance of contracts. Legal obstacles may exist within a country or between two countries involved in a pipeline project. For instance, poor legal structure within a country, inconsistent or incompatible legal traditions and systems between countries, or adherence to different international treaties that are inconsistent or incompatible may make cross-border projects difficult.

  Governments should seek to put in place structures and systems for:

  • Effective and fair implementation of regulations;
  • Respect for the sanctity of contracts;
  • Enforcement of contracts.

  Governments might consider accepting international arbitration for the settlement of disputes with investors, and adhering to the New York Convention on the enforcement of arbitral awards, as a sign of their willingness to adhere to agreements with international investors.

- **Regulatory risks:** This is the key area of government's involvement. The governments of each country engaged in a cross-border project should seek to adopt clear, transparent and predictable legislation and regulation governing private investments in gas activities.

  • **In producing countries:** governments should introduce upstream legislation (licensing, including E&P licenses and joint operation agreements or Production Sharing Agreements) which is attractive to investors in comparison with other countries, taking into account the country's geological potential, sovereign risks and strategic position.

  • **In transit countries:** governments should establish a reliable legal system governing transit activities (bilateral treaties).

  • **In importing countries:** Governments should seek to establish a consistent framework for the development of gas consumption. It will differ according to the maturity of the gas market. It can be a decisive factor in the case of emergent markets. In an emerging gas market like China, this implies a regulatory system for the downstream sector, which protects suppliers and consumers alike. In the start-up phase, investors' protection is crucial to amortise the investment. Governments should seek to ensure that, as far as possible, any changes in the regulatory regime do not modify the economics or legal basis of a project. For instance, when state-owned assets are privatised, the government can ensure that the commitments taken (or contracts signed) by the former state-owned company will be honoured.

International treaties as a means to facilitate cross-border gas projects

Cross-border gas trade, in both pipeline and LNG forms, accounted for 620 bcm or 24% of world gas consumption in 2000, and the trend is set to grow in the future. So far, trade is conducted under bilateral treaties or agreements (for North Sea gas), host-government agreements (e.g. oil transit to Georgia) and other international agreements. Most of them are publicly available and can be found under the UN Treaty system.

A notable international development in the area of energy trade agreements is the Energy Charter treaty[12], which defines a common minimal legal framework to protect private energy investment (mainly by dispute settlement – or so-called diagonal – mechanism under Article 26) and to ease transit (mainly by the transit provisions of Article 7 for its signatory states). To enhance the Charter provisions in the area of energy transit, the Energy Charter Conference of December 1998 created a Transit Working Group, with the aim of elaborating commonly-accepted principles governing inter-state energy transit *via* oil and gas pipelines or electricity grids (Box 7.9).

Box 7.9

Energy Charter Rules in Energy Transit

The Transit Working Group of the Energy Charter Conference had two primary tasks:

- to prepare legally non-binding model agreements on energy transit, and
- to prepare a legally-binding protocol on transit.

Non-binding Model Transit Agreements (MTA):

The Transit Working Group has identified three different types of MTA that may be of help to address key issues of interest to important stakeholders, such as states and investors/operators/shippers and users:

- *Model Intergovernmental Agreement*: Government-to-government agreements addressing project-specific issues between the producing and the transiting state that might help to create a framework that protects the interests of investors in both states..
- *Model Host Government Agreement:* Investor-government agreements addressing transit through planned new facilities as well as transit through existing operational facilities.
- *Model Transit Transportation Agreement*: Investor-shipper-operator-user and state entities agreements addressing specific transport-related issues that emerge from transit through operational facilities.

Negotiations on a Legally Binding Transit Protocol:

Since its creation, the Transit Working Group has made progress in preparing a Draft Protocol on Transit (DPT). However as of May 2002, negotiations continued and substantive points remain to be settled. The DPT applies both to energy materials and products in transit through energy transport facilities, and to those facilities themselves used for transit.

The DPT addresses the issues of energy transit in more detail than the Energy Charter Treaty Article 7. It emphasises the obligation of the signatory states to take active measures in order to implement the objectives of the DPT, rather than just not placing obstacles, as the Treaty mostly requires.

12 Several notions related to the Energy Charter process need to be clearly understood. The *European Energy Charter* is a political declaration of intention to promote East-West energy co-operation, adopted by 52 States and the European Community in December 1991. The *Energy Charter Treaty* is the legally-binding multilateral agreement, developed on the basis of the European Energy Charter. It was opened for signature in 1994, and entered into force on 16 April 1998, after ratification by 40 signatory states. As of January 2001, 44 of the 51 signatory states had ratified the Treaty. The *Energy Charter Conference* is the Treaty's governing body. The *Energy Charter Secretariat* was established in Brussels in 1996, as the executive body of the Energy Charter treaty to support the Energy Charter Conference and to take up specific functions on the Conference's behalf, such as facilitating transit conciliation and negotiating the Transit Protocol.

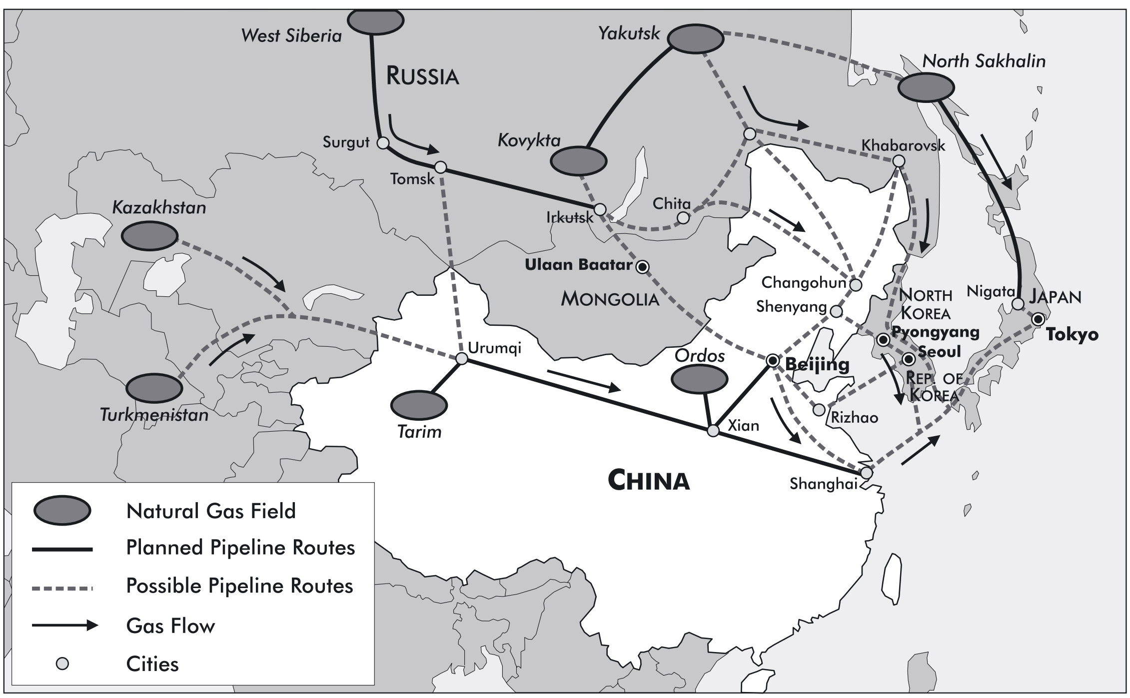
China became an observer of the Energy Charter Conference in 2001. Its further participation in the process and ultimate membership may depend critically on the Russian ratification of the treaty. Both countries' participation in the Treaty would facilitate the cross-border oil and gas projects that are envisaged in north-east Asia.

NORTH-EAST ASIA GAS PIPELINE NETWORK: PROSPECTS AND KEY CHALLENGES

Over the last few years, there have been a number of proposals to develop pipelines that would transport natural gas from Russia's east Siberia and far east to consuming areas of north-east China, Korea, and Japan. These pipelines could be linked in the future to those transporting gas from west Siberia and Central Asia to ultimately form a North-east Asia Natural Gas Pipeline Network (Figure 7.4).

Figure 7.4

Plan for a North-east Asia Natural Gas Pipeline Network[13]



Source: North-east Asian Gas & Pipeline Forum, September 2000.

13 The indication of pipeline routes within China does not reflect the actual situation, which is shown in Figure 7.1.

Key promoters include the Asian Pipeline Research Society of Japan, the Energy Systems Institute of Irkutsk, the Skhaneftgaz of Yakutsk, the Korea Pan-Asian Natural Gas & Pipeline Association, the Asia Gas & Pipeline Co-operation Research Centre of China, and the Petroleum Authority of Mongolia. Annual conferences on the North-east Asian Natural Gas Pipeline have been held in different locations since 1995. The 1997 conference established the North-east Asian Gas & Pipeline Forum (NAGPF), with the main mission of contributing to the rapid promotion of the North-east Asia Natural Gas Pipeline Network, exchanging information and deepening mutual understanding.

The prospect for a North-east Asia Natural Gas Pipeline Network seems to be a long and distant goal. There are numerous challenges ahead for any cross-border pipeline project in that region. Key challenges include:

- Developing the natural-gas consuming market in north-east China, especially the large gas off-takers that serve as anchors for these large import projects. The issues of market development related to gas for power generation and local gas distribution have been discussed in Chapters 4 and 5.
- Continuing the efforts to align the interests of all partners along one specific project and mounting an international consortium.
- Serious feasibility studies to firm up gas reserves in east Siberia, to identify gas demand areas, to select the pipeline route, and to provide realistic and detailed economic and financial calculations.
- Competition from alternative gas supply sources, in particular LNG for the development of China's gas market and the expansion of the Korean and Japanese markets.
- Resolving all important issues related to a cross-border gas pipeline project as outlined previously, especially the mitigation of risks related to those projects.
- Securing the required financing for the projects.
- Political support from all countries involved.

RECOMMENDATIONS

Building a long-distance gas pipeline in a financially sound way is a daunting challenge in all parts of the world. It is especially so in China, where the gas market is just being developed and other essential framework conditions for investment and regulation are not yet firmly elaborated. As China goes ahead with the construction of the required infrastructure to expand the gas market, it needs to pay particular attention to its weak areas in downstream market development and investment framework. It should also go beyond project-specific issues to formulate a clear gas policy as well as an energy policy that would address the long-term structural and regulatory issues of the gas industry.

Based on the analysis of the issues surrounding long-distance gas pipelines, the following recommendations are formulated:

The Chinese government should:

- Define an enabling policy framework for gas infrastructure building, through a clear and reliable gas policy. Facilitate the building of long-distance gas pipelines by creating a clear, transparent and predictable framework for private investment. This includes procedures for project approval, partnership arrangements, fiscal policies, and leaving the market to decide wholesale gas prices.
- Take active measures to encourage downstream gas market development by private investors as a means of supporting pipeline projects.
- Mitigate the high-risks that are inherently present in any large-scale project, especially those related to the legal framework, policies and regulations.
- Leave pipeline construction and operation issues to the project sponsors and operators, but focus on long-term policy issues that any specific pipeline project may raise.
- On the West-East Gas Pipeline project, the Chinese government should:
  - Facilitate downstream gas market development by encouraging gas consumption, especially by large anchor projects such as power stations, by providing incentives, reducing project approval burdens, etc.
  - Step up efforts in downstream market development by backing the long-term gas purchase commitments of state-owned off-takers based on their realistic future demand evaluations and by reducing the burden in downstream gas project approval procedures.
  - Strengthen the link between the west section of the pipeline and downstream gas market development.
  - Recognise the project's unique set of characteristics when generalising the application of policies and measures to other gas infrastructure projects.
  - Act as a convenor to encourage the alignment of interests between upstream and downstream players, and between domestic and international participants of the project.
  - Pay attention to long-term structure and regulatory issues in defining the framework conditions for this particular project and make sure that short-term project decisions do not jeopardise the long-term goals of gas market development.
  - Liberalise price control at wholesale level (both at well-head and city-gate) and encourage net-back gas pricing (both are necessary conditions for take-or-pay contracts)
  - Set clear and stable fiscal rules (taxes and concession fees) over the project's lifespan, by taking due consideration of the risk-reward balance at different stages of the project.
- On the North-east Natural Gas Pipeline Network, the government should strengthen co-operation with all concerned countries, prepare the market with a serious and independent market study, adhere with other countries to international rules on investment and transit, and create conditions for the future realisation of the pipelines.

GAS MARKET DEVELOPMENT THROUGH LNG IMPORTS

Highlights:

- *China's east coast areas have high potential for gas market development via LNG imports. Achieving this potential needs an alignment of interests between project promoters, future gas users, and local and central authorities.*
- *LNG supplies are widely available, and can accommodate any future growth in China and in the Asia-Pacific region. However, the traditional LNG trade model is changing to reflect the evolving market realities both upstream and downstream, with less stringent conditions in price, volume and contract duration.*
- *There are a number of challenges to be tackled in the Guangdong project, most of which are similar to the West-East pipeline project. In the longer term, the key to successful LNG market development in China is to replicate the positive experiences learned from the Guangdong pilot project and keep the same level of support by the central government for future projects.*

With the first project in Guangdong already under construction, China has embarked on LNG imports, a business that holds strong market potential along its east coast. While most of the market development issues related to LNG are the same as those of pipelined gas, there are also some specific issues that merit a special analysis. This chapter provides a brief description of LNG market prospects in China and the surrounding international context, and addresses some of the LNG-specific issues.

DISTINCT CHARACTERISTICS OF LNG PROJECTS

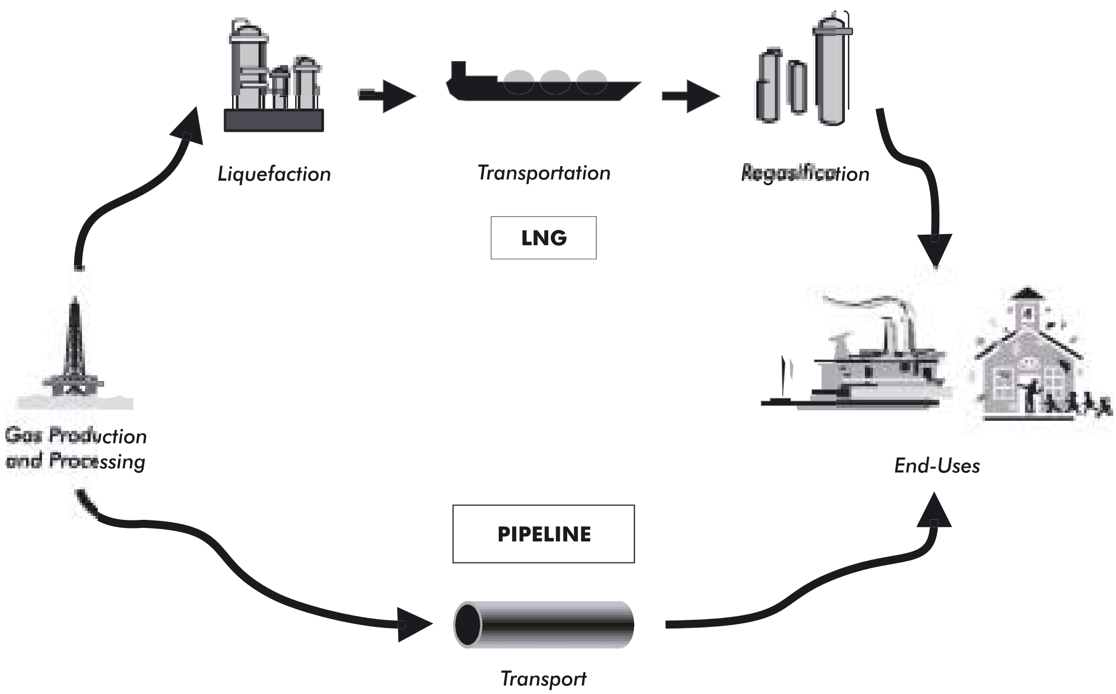
LNG-based gas supply has a number of distinct characteristics compared to large or medium-scale pipeline gas projects:

- LNG inevitably raises issues of international energy trade that are not always present in pipeline-based gas projects. This means that LNG projects always involve commercial relations based on foreign exchange (e.g. US$), which is not the case for domestic pipelines. The international trade aspect introduces additional risks into the LNG value chain associated with exchange rates, duties and international relationships.
- Compared to pipeline projects, LNG involves at least two more links in the physical chain: gas liquefaction and LNG regasification (Figure 8.1).
- These additional links increase the complexities of commercial structures compared to pipeline projects.
- LNG is slightly more flexible than pipelines in the sense that LNG tanker destinations can be changed physically, which allows for swap deals between buyers, and which may lead to the emergence of an LNG spot market. These developments are embryonic, and liquidity in the spot market is still very limited.

- There may be stronger public perceptions of safety issues and risks related to LNG that require the application of rigorous safety and environmental standards for LNG facilities.

Figure 8.1

Gas Chain by LNG and Pipeline



Despite these differences, LNG-based gas supply and pipeline gas supply share most of the common issues.

While in theory an LNG-based supply chain does not require a direct linkage between gas source and market, in practice long-term contractual relationships between LNG source and market are required to underpin the large upstream development costs and shipping investments. The spot market in LNG remains small and is inadequate as a source to underpin the development of a significant regional or national gas industry. Long-term contracts with take-or-pay obligations on the LNG buyer remain the norm, in the same way as for pipeline projects.

The challenges and risks faced in developing the LNG-based market are essentially the same as for a pipeline-based project. Both involve substantial investment in the interlocking elements of the gas chain. The development of a secure core market to underpin infrastructure investments in the gas chain is critically important. In addition, the regulatory environment and investment climate must be sufficiently well defined and stable to provide the confidence and assurance to investors in making their long-term investment decisions.

LNG cost

LNG investment cost comes on top of upstream investment in gas production infrastructure. To give an indication, a new LNG train with a capacity of 4.2 million tonnes per annum costs in the order of US$1.3 billion, while a new LNG tanker costs between US$170 and US$200 million. LNG receiving terminals (and the associated infrastructure to deliver gas to the market) cost between US$600 million and US$1 billion. A typical multi-train LNG export project could therefore require both the supplier and the buyer to make a total commitment of as much as US$6 billion each – that is, a total initial investment of US$12 billion on infrastructure.

Between 1990 and 2000, gas liquefaction costs fell by between 25-35%, and shipping costs by 20-30%. The important cost reduction in liquefaction comes largely from the increase in train size, improved fuel efficiency (mainly from high-efficiency gas turbine in on-site co-generation facilities), improvement of equipment design, the elimination of gold-plating, and better utilisation of available capacity. There is scope for further reduction, but this may not be achievable to the same extent.

LNG supply contract negotiations also take time. From the start to the first shipment, it generally takes a minimum of five years – an often tortuous and frustrating exercise that can test the financial, political, legal and technical mettle of all involved.

Despite these complications, several countries, most notably Japan and South Korea, have successfully developed gas industries based solely on LNG. In other countries such as France, Belgium and Spain, LNG also constitutes a significant proportion of gas supplies.

CURRENT STATUS OF PLANS TO IMPORT LNG

The Guangdong LNG pilot project

The idea of importing LNG to Guangdong had been raised as early as the late 1980s and early 1990s. The province is the most dynamic in China, and was experiencing a very high economic growth rate, averaging around 15% per year. To meet its energy needs, it relies mainly on domestic coal, which has to be transported from the northern part of the country, involving transportation of several thousands of kilometres. Without subsidised transportation costs, domestic coal is more expensive than imported coal from Australia or Indonesia. To meet its electricity needs, Guangdong also built a number of oil-fired power plants.

Guangdong is probably the best choice of province for China's first LNG plant[1]. The population of 75 million contributes about 10% of the country's GDP, making the per capita GDP double the national average. The province accounts for about 40% of China's exports, and yet imports most of its primary energy supply and a growing proportion of its electricity.

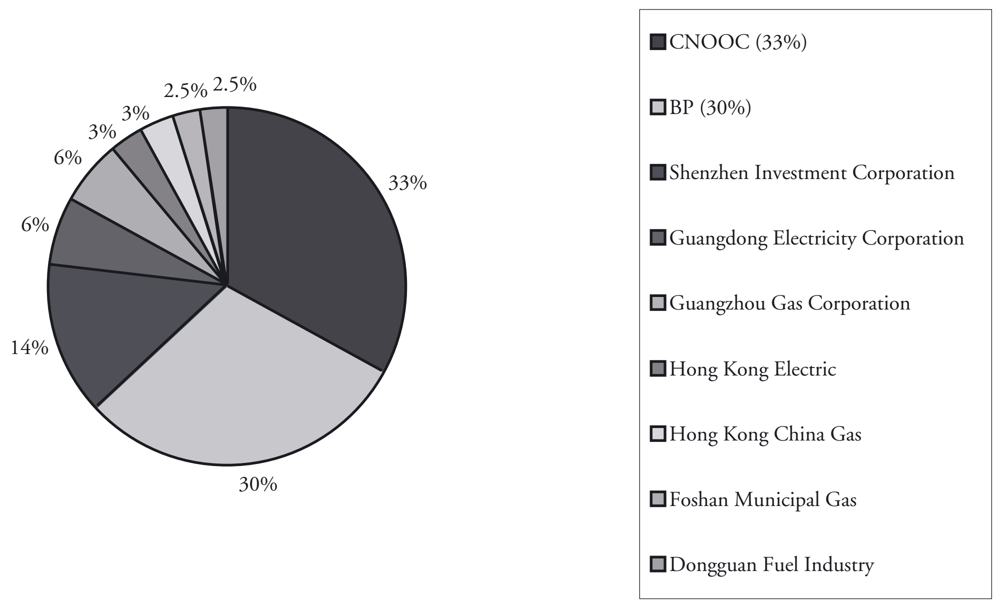
1 Although the LNG project in Guangdong is the first large LNG-related project, it is not the first commercial-scale LNG facility in China. The first such project is an LNG peak-shaving storage installation at Shanghai, which was built by Sofregaz of France in conjunction with Technigaz, on behalf of the Shanghai Municipal Gas Company. It came into operation in the first half of 2000.

The partnership

Official preparation of the project started in 1993, with formal central government approval in 1999. Foreign investors were allowed to participate in the receiving terminal, regasification and related infrastructure building, but at that time foreign investment guidelines stipulated that the Chinese side must hold the majority share. In the year 2000, two rounds of bidding took place: the first in the summer, in which a short-list of four foreign consortia was drawn up; the second in the autumn from which a single foreign partner was to be selected. In March 2001 it was announced that BP had been selected to participate in this project with 30% of the share. Figure 8.2 shows the partnership composition of the project.

Figure 8.2

Partnership of the Guangdong LNG Project



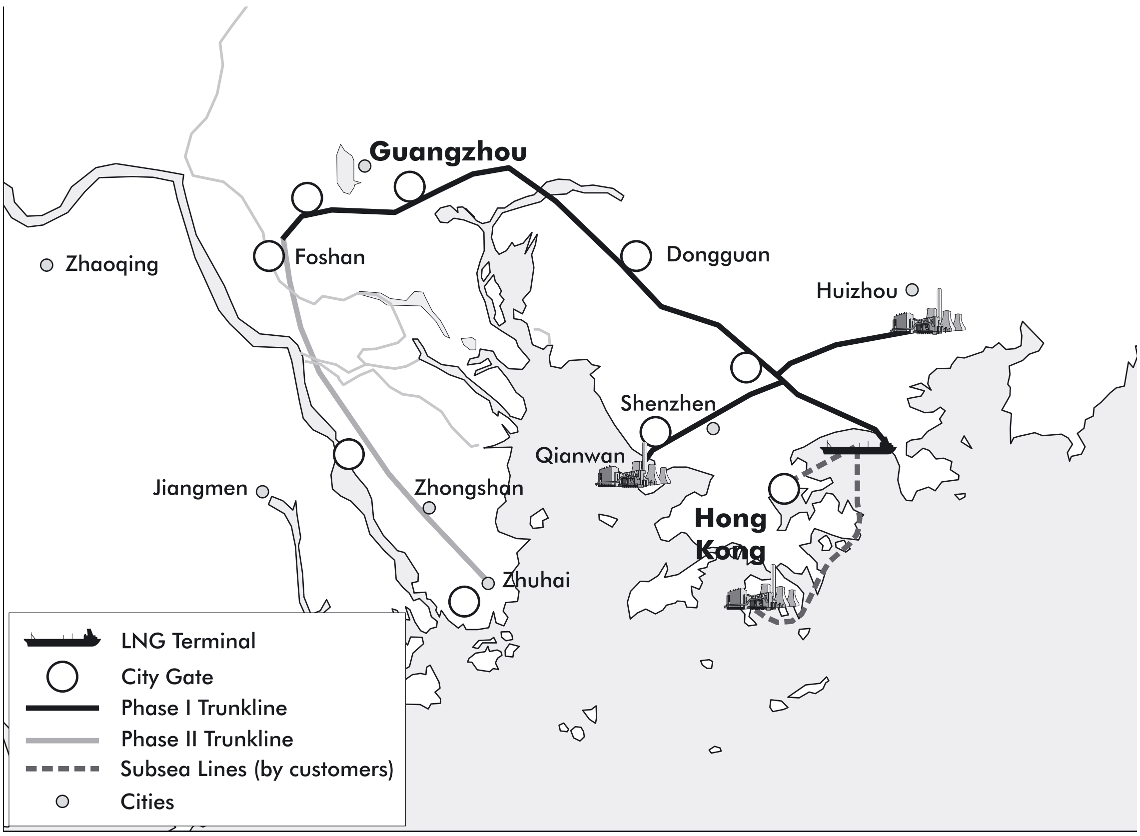
Source: SDPC.

The terminal and related infrastructure

The terminal is scheduled to have two phases. The first phase, with an LNG capacity of 3 million tonnes per year (mt/y), is scheduled for completion by 2005. It includes one trunkline of 215.4 km and two lateral lines to Huizhou power plant (32.6 km) and to Qianwan power plant (78.8 km). A storage tank of 160,000 m^3 is also planned. Two sub-sea pipelines, one to be built by Hong Kong China Light and Power (92 km) and another by Hong Kong China Gas (40 km) are also scheduled to export part of the regasified gas to Hong Kong. The second phase will add a receiving capacity of 3 mt/y to the terminal, extend the trunkline by 181.7 km and build another storage tank of 160,000 m³. By 2009, when phase II is completed, the project will be capable of handling up to 8.2 bcm of natural gas annually, which is not far below the 12 bcm West-East Gas Pipeline project. Figure 8.3 illustrates the extent of the infrastructure that will be developed around the terminal.

Figure 8.3

Guangdong LNG Receiving Terminal and Related Infrastructure

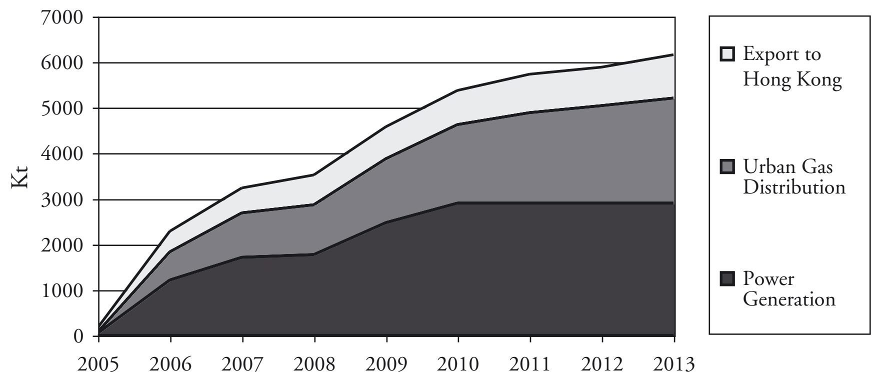


Market build-up

Figure 8.4 shows the expected demand build-up of LNG. It is expected that when the whole project comes into full operation by 2012, power generation and urban gas distribution will take respectively 49% and 36% of the total LNG, with the remaining 15% going to Hong Kong.

Figure 8.4

Demand Build Up for Guangdong LNG



Source: Guangdong LNG terminal & trunkline project joint executive office, April 2002.

The cost

The first phase of the LNG receiving and regasification terminal and related trunklines are estimated to cost US$600 million. But a project of that scale will need at least 2,000 to 3,000 MW of committed power generation capacity to be developed at the same time. Total required investment for the first phase of 3 mt/y, including infrastructure for receiving, regasifying, transporting, distributing and using the gas (including the new power plants), is about $3 billion.

Supply sources

In November 2001, seven supplier companies/countries (Australia LNG, Malaysia LNG, Sakhalin, RasGas of Qatar, Tangguh of Indonesia, Yemen LNG and Iran) were invited to submit bids, and all but Iran purchased the bidding packages. In January 2002, Australia LNG, Indonesia Tangguh, and RasGas of Qatar were shortlisted for further negotiation. In August of the same year, it was announced that Australia LNG had won the 25-year contract as the sole supplier for the Guandong first phase with 3 mt/y, to start by 2005/06. Gas will come from Australia's North West Shelf with partners including Woodside Energy, BHP Billiton Petroleum, BP, Chevron Texaco, Japan Australia LNG (MIMI) and Shell. As part of the deal, CNOOC will acquire a 25% interest in the fifth LNG train of the North West Shelf, which is to supply the Guangdong terminal.

Other future LNG projects

Other areas that hold potential for LNG import projects include the coastal provinces of Fujian, East China (Zhejian and/or Shanghai), and Shandong and/or Liaoning.

In October 2001, CNOOC and Fujian provincial government signed an agreement to build a 2-3 mt/y LNG receiving terminal in the first phase, with attached trunkline. The first phase will be completed by 2007 and will be expanded to 5 mt/y during the second phase to be completed by 2011. The central government has recently given the green light for the start of preparatory work on the project, with the aim of building the terminal within five years. This terminal, a joint investment by CNOOC and the Fujian Investment & Development Co. Ltd., will have a handling capacity of 2.5 mt/y of LNG. CNOOC, the parent of the listed CNOOC Ltd., will provide 60% of the total investment. Construction of the first phase will start in 2004.

In September 2002, Indonesia and China signed a 25-year, US$8.5 billion sales and purchase agreement for the Tangguh gas field, in which BP holds a 50% interest, to supply up to 2.6 mt/y of LNG to Fujian at the completion of the first phase. It was reported that CNOOC will purchase from BP an equivalent 12.5% stake in the Tangguh LNG project.

For east China and Shangdong and/or Liaoning, no firm plan is yet available. CNOOC plans to have a first phase LNG capacity of 3 mt/y by 2010 in east China, and 1.5 mt/y in Shangdong.

The outlook for LNG in China

In theory, China's coastal provinces have considerable potential for future LNG expansion, but achieving this potential will depend not only on the successful completion of the Guangdong pilot project, but also on a number of other parameters. The World Bank has conducted a study on the market potential in the east China region. It concluded that LNG and other gas supply options are complementary and suggested that all steps should be taken to move ahead with the development of an LNG industry in China. The study also addressed ownership structure and trading arrangements, regulation, financing, and other key issues for LNG development in China. Key conclusions are provided in Box 8.1.

Among the positive factors in these provinces are their vibrant economies and the associated strong need for a secure supply of energy, especially in its clean and high-quality forms. The benefits of LNG uses are widely recognised, and there is a high degree of support from both local and central authorities.

Box 8.1

Key Conclusions of World Bank Report on China LNG Imports

- LNG and other gas supply options are complementary, and LNG and offshore gas are essential to satisfy the projected energy demand in the shorter term. All steps should be taken to move ahead with development of an LNG industry.
- The critical factors for LNG development are deciding who the LNG buyer should be and the form of organisation that most easily provides long-term financial security to support the project risk. A simple, short, and well-defined contract structure between the LNG buyer and the off-takers is a critical element in reducing risks.

- The LNG buyer needs to have the incentives to encourage and assist in the rapid development of markets for the gas. The short-term focus should be on power generation, and the longer-term focus on the non-power sectors.
- The reform of the power sector, which is designed to expose generators to short-term competition, could make it more difficult for new power plants to provide the long-term guarantees needed for the gas off-take agreements. Careful design of that reform is therefore required, as well as the design of long-term gas and power contracts.
- In the absence of a primary legal framework for gas distribution, alternative instruments that provide long-term exclusive rights to sell the gas to match the obligation taken on by the LNG buyer will be needed.
- The institutional structure should allow for long-term competition between gas suppliers through open access to onshore pipelines and import terminals as the market expands.
- The financial attractiveness of LNG development is sensitive to a number of uncertainties. They include securities and guarantees that can be provided in the absence of an overall sovereign guarantee; project rates of return; availability of foreign exchange; creditworthiness of the off-takers. Strategic factors such as long-term security of supply and environmental benefits are also vital to the basic decision to pursue the project.

Source: World Bank (2000), "Liquefied Natural Gas in China: Options for Markets, Institutions and Finance" (Discussion Paper number 414).

Despite these causes for optimism, there are a number of issues that raise questions about the rate and nature of the development of the LNG industry in China:

- First, there is as yet no coherent energy policy statement that clearly defines the role of imported LNG in China's energy mix and the value of supply diversity. There seems to be no consensus in Beijing on the necessity for large imports of LNG, as some leaders would prefer either the development of domestic gas sources despite the long distances involved, as in the case of east China, or the development of nuclear power for the growing electricity needs in the coastal areas.

- Second, China's electricity sector is going through an important transition period with the breaking down of the State Power Corporation and the introduction of competition. Power generation provides the most important anchor to new pipeline gas and LNG import projects. Experiences of other Asian countries showed that power sector regulation started to affect the traditional foundation of the LNG business (see section below on Asian LNG demand prospects). The power sector reform process in China will last for a number of years, which will affect the decision-making process on new projects.

- A third factor, which is a consequence of the first one, is the fear that none of the other LNG projects will have enough political weight to obtain a quick green light from the central government.

- The last factor of uncertainty is the nature and scale of continuing government support for foreign participation in future projects. Chinese practices usually attempt to ensure the success of one or two pilot projects as a showcase with a number of incentives and other kinds of support, but there is a big question as to whether these same incentives and support will hold for subsequent projects [2].

In conclusion, the future of the LNG business in China will have to depend more on the economics of the project itself. At the same time, a reasonable degree of government support will also be needed on an ongoing basis to support these projects as demand builds. Decisions on where to locate terminals will be influenced by both technical considerations (e.g. possibility for building deepwater harbours) and economic factors, especially the distance to major demand centres.

REGIONAL LNG MARKETS TRENDS AND PROSPECTS

An important issue is how China's LNG business is positioned in the context of regional and global markets. This section addresses the issue by analysing trends in the supply and demand of LNG.

Asia-Pacific LNG demand

Current importers

Asia currently hosts three large LNG importers (Japan, South Korea and Chinese Taipei), which accounted for 72% of world LNG demand (138.5 bcm) in 2000. Japan was the first Asian country to import LNG, and currently is the biggest importer, accounting for three-quarters of the total Asian demand in 2000. South Korea, which began importing LNG in 1986, has a rising share, accounting for 20% of the Asian demand. The rest goes to Chinese Taipei, which started to import LNG in 1990. Table 8.1 shows the current sources of supply of these importers.

Table 8.1

LNG Supply Sources to Asian Importers

Importer	Japan	South Korea	Chinese Taipei
Supply Sources	Australia, Brunei, Indonesia, Malaysia, Oman, Qatar, U.A.E. and United States	Brunei, Indonesia, Malaysia, Oman, Qatar and U.A.E.	Indonesia, Malaysia

2 China's power sector can be used as an analogy for uncertainties on LNG projects. In the late 1980s, China successfully concluded a first build-own-transfer (B.O.T.) project by a foreign company, which attracted a number of other foreign companies to undertake joint ventures with Chinese power companies to upgrade or construct generating plants, but most of these projects have encountered substantial legal and administrative problems.

Other new importers

Besides China, other new LNG importers will enter the Asian LNG market in the coming years. Among them, India holds the strongest market potential.

Like China, India has no LNG terminal as yet, but there are currently no less than 11 greenfield projects under consideration in this country, many of which may never make it past the planning stage. Two projects are under construction, one initially started by Enron in Dabhol in Maharashtra state with a supply capacity of 5 mt/y. Enron already signed supply contracts for 3.7 mt/y with Gulf exporters. But the recent collapse of the company has put the project on hold, as Enron and its partners have put it up for sale. Another is the Petronet LNG project at Dahej (Gujarat state). The project is to bring in gas in late 2003 or early 2004, and to build up to a capacity of 5 mt/y by 2005. This could later be expanded to 8-10 mt/y. In addition, there are a total of six other projects under consideration: Papavav in Gujarat (5 mt/y), Trombay in Maharashtra (3 mt/y), Cohin in Kerala (2.5 mt/y), Ennore in Tamil Nadu (2.5 mt/y), Kakinada in Andhra Pradesh (5 mt/y) and Gopalpur in Orissa (5 mt/y).

The most promising is perhaps the Dahej project, and depending on the success of sales negotiations, the Dabhol one. Many obstacles remain before any of the other proposed projects can bring their first LNG cargo. In particular, the creditworthiness of many State Electricity Boards is very poor, which will not help in backing the needed financing arrangements. There is a wide range of uncertainty on the Indian LNG demand level; it could be between 7-10 mt/y by 2005 and 13 to 20 mt/y by 2010.

Other Asian countries have also had an LNG project on their drawing boards at some point. They include Singapore, which was concerned about its over-dependence on its single source of supply in Malaysia. It undertook a feasibility study for an LNG project as an alternative to the Malaysian supply when the current 15-year contract expires in 2007. Thailand and the Philippines each had an LNG proposal in the mid-1990s, but both have preferred to develop their indigenous gas resources or to import by pipeline from neighbouring countries. Industry sources indicate that an LNG/power project is at a well advanced stage in the Philippines. Pakistan also undertook an LNG import feasibility study in 2000.

Asian LNG demand prospects

In sum, the future prospect of Asian LNG demand, up to 2010, depends both on the growth potential of existing importers and on the performance of India and China as two newcomers. A large number of existing LNG contracts will be due for renewal in the coming years, and the new deals are expected to have better terms in price and flexibility, to reflect both the important cost reductions achieved in recent decades and the changed market situation.

According to a 2000 forecast by the International Gas Union, Asian demand for natural gas is expected to grow from 263 bcm in 1998 to 470 bcm in 2010. LNG use, in particular, is expected to continue to grow at around 5% a year, from 92.3 bcm in 1999 to between 146 to 184 bcm in 2010. This growth is expected to come not only from Japan, South Korea, and Chinese Taipei, but also from newcomers China and India.

In Japan, gas demand growth slowed in the 1990s due to continued economic stagnation, so future gas demand will critically depend on the rate and timing of economic recovery. Other drivers of gas demand include cost reductions in the gas supply and the difficulties of building a large number of nuclear power plants as a means to fulfil Japan's CO_2 reduction commitment under the Kyoto Protocol. However, due to right-of-way difficulties, the underdeveloped inland gas transmission system seriously undermines any future demand build-up in the gas distribution sector. There is also the growing shortage of suitable sites for LNG receiving terminals. Japan has 22 receiving points, but it is becoming increasingly difficult to find suitable sites in the vicinity of major markets.

Japanese power utilities, which use three-quarters of the LNG, are undergoing a partial deregulation process, which may undermine their ability to make new long-term "take-or-pay" commitments when most of the LNG supply contracts come up for renewal during the 2007-2010 period.

The same uncertainties face two other existing importers. In South Korea, the world's second largest LNG importer, the monopoly state-owned LNG buyer, KOGAS, is going through a restructuring process, with its import and wholesale division to be unbundled into three entities, of which two will be sold. The power utility, the Korea Electric Power Corporation (KEPCO) is also scheduled for privatisation during 2002. In Chinese Taipei, a new procurement law has ended the monopoly right of the Chinese Petroleum Corporation (CPC) in LNG imports.

The creditworthiness and the ability of LNG importing utilities (often backed by government) to commit to 20-year plus take-or-pay contracts have been the foundation for the vast majority of the major LNG projects that have been built. The changes that are occurring in the Asian utility sector are likely to alter this traditional model for LNG.

Under deregulation, former monopoly LNG buyers become exposed to the possible loss of clients to competitors such as Independent Power Producers (IPPs). This reduces their ability to forecast future LNG requirements and to enter long-term take-or-pay contracts. They will therefore need more flexible measures, such as short-term contracts with re-opening clauses and less stringent conditions on take-or-pay contracts. Price indexation to oil may be lessened. Other schemes, such as spot deals, swaps, and backhauls are also likely to be developed.

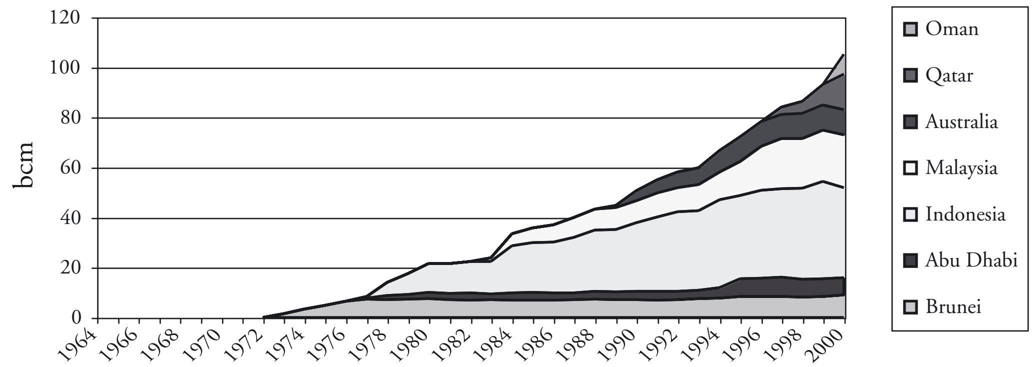
Regional LNG supply prospects

Asian markets will continue to be supplied by LNG exporters in the east of Suez Canal. In 2000, the east of Suez accounted for 74% of the 137 bcm of LNG exported worldwide.

Historically, the east of Suez exporters supplying the Asian markets include: USA-Alaska (1969), Brunei (1972), U.A.E.-Abu Dhabi (1977), Indonesia (1977), Malaysia (1983), Australia (1989), Qatar (1996), and Oman (2000). Figure 8.5 provides the evolution of these exports (excluding Alaska, which currently exports 1.24 mt/y to Japan).

Figure 8.5

Evolution of East of Suez LNG Exports



LNG supply is abundant in Asia. All current suppliers have additional capacity and/or expansion plans, and are waiting for demand and import capacity to increase in order to justify expansion or new greenfield projects. In Indonesia, which has a current capacity of 27 mt/y, two greenfield projects are scheduled: Natuna for a minimum capacity of 5 mt/y and Tangguh for a capacity of 6-7 mt/y.

Malaysia has a current capacity of 15 mt/y that supplies LNG to all three Asian importers. A two-train extension project in Bintulu, with a capacity of 6.8 mt/y, is scheduled for completion in 2002/03.

Australia currently has a supply capacity of 7.9 mt/y provided by the three trains in the North West Shelf. A fourth train with a capacity of 4.2 mt/y is under construction for completion by mid-2004. A fifth train will be constructed to supply China's Guangdong province. Three greenfield projects by Chevron Texaco, Philips, and Woodside are also in the planning stage. If they proceed as planned, they could add a total capacity of 12.3 mt/y by 2010.

Brunei's current supply capacity is 7.2 mt/y. An expansion project with 3-4 mt/y of new capacity is planned for completion by 2008.

Qatar, Abu Dhabi and Oman are the current LNG exporters in the Middle-East. Qatar has two liquefaction plants at Ras Laffan (Qatargas with three trains and a total capacity of 6 mt/y and RasGas, with two trains and a capacity of 6.4 mt/y). In addition to supplying the Asian markets, it also supplies Turkey, the United States, and Spain. Ras Laffan LNG has a contract with India's Petronet to supply 7.5 mt/y and is engaged in a major expansion programme. Oman started LNG exports in 2000 and has one two-train liquefaction plant with a total capacity of 6.6 mt/y. A third train of 3.3 mt/y will be added by 2004. Oman had a gas sales contract with Enron's Dabhol project in India, but is trying to divert it to other destinations. Abu Dhabi was the first Gulf LNG exporter (started in 1977) and has a three-train liquefaction plant with a combined capacity of 5.5 mt/y.

There are a number of new Gulf LNG exporters scheduled to begin operations in the coming years. Iran, which has the second largest proven gas reserves[3] after Russia, plans to start LNG export by 2006 with a two-train liquefaction plant and a total capacity up to 7 mt/y. A two-train project has also been proposed in Yemen.

Alaska started to export LNG to Japan in 1969 under two contracts with Tokyo Gas and Tokyo Electric Power Corporation. The current production capacity is 1.4 mt/y. A new LNG project near Port Valdez with gas pipelined from the Prudhoe Bay is currently at the planning stage, with completion date scheduled for 2007. This would add 7 mt/y of LNG supply capacity.

Russia's Sakhalin island has one LNG project (Sakhalin 2) planned for construction. It would be a two-train plant with a supply capacity of 9.6 mt/y, to come on stream by 2006.

All the expansion or greenfield projects described above can only be developed if the markets in potential importing countries can be effectively developed. Without downstream expansion, many of these projects will be either delayed or shelved.

Table 8.2 summarises the demand and supply situation for the region. Overall, the east of Suez market will be a buyer's market in the coming years, as is the case for the rest of the world. Competition between suppliers for new markets will remain strong. In a buyer's market, new LNG contracts are likely to be more favourable to buyers than those concluded in the past. Buyers will have an increasing interest in the upstream business for reasons of supply security, while sellers will be keen to participate downstream for market security reasons. In this way, risks may be more evenly distributed between the upstream and downstream players[4].

Table 8.2

Regional LNG Demand and Supply Prospects

	Evolution of LNG Demand in Asia	
	Demand in 2000 (bcm)	Forecast Demand in 2010 (bcm)
Total	98 (or 72.6 mt)	153.5-200 (or 113.7-148.2 mt)
Japan	72.46	82.5-109
Korea	19.68	32-36
Chinese Taipei	5.9	14-18
China	0	11-14
India	0	13-20
Others	0	1-3

3 According to Cedigaz, Iran has 25.8 tcm of proven gas reserves.

4 There have been many papers on the emergence of a new business model for LNG trade. Mutual investments by upstream and downstream players form part of this new model. Also, in the new scheme, shipping companies will no longer be project dedicated. They will become "free" to provide dedicated transportation services, without being bound to a specific destination. Spot or short-term markets may also emerge, and new LNG projects may start up without buyers' full commitment. These factors will obviously increase the commercial risks of projects, and new ways of risk control, such as hedging mechanisms, are also being developed.

	Evolution of East-of-Suez LNG Supply	
	Contracted Supply in 2000 (bcm)	Forecast Supply Capacity in 2010 (bcm)
Total	101 (or 74.8 mt)	164.8-213.2 (or 122 – 158 mt)
Indonesia	36	42.4-50.5
Malaysia	21	30.7
Brunei	9	13.7-15
Australia	10.7	20.5-25
Abu Dhabi	6	7.4
Qatar	13	30.7-39.6
Oman	3.6	13.5
Yemen	0	4.2-8.4
Iran	0	0-5.4
Russia	0	0-6.5
Alaska	1.7	1.7-11.2

Note: Conversion between LNG weight and volume is based on 1 mt of LNG =1.35 bcm of natural gas.
Source: IEA.

KEY ISSUES FOR DEVELOPING LNG IMPORT PROJECTS IN CHINA

The Guangdong LNG project is a key pilot project in China, and represents an important part of the country's overall natural gas utilisation arrangement. Plans exist to develop similar projects in other coastal areas of China. However, as with any major infrastructure investment, there are many challenges facing this and other LNG projects.

Gas market development and marketing

The development of an end-use gas market to support an LNG-based supply chain is a challenge in terms of both timing and scale. The extent of the investments required demands that the various links in the gas chain are both synchronised and are of a scale sufficient to deliver gas at a competitive price.

China has the advantage of a dense population base, a growing economy, and a vibrant industrial sector that can provide the basic long-term demand to underpin an LNG-based value chain of feasible scale. However, the complications of timing and economies of scale mean that there is a need for anchor customers (power plants and large industrial users) to take large volumes from the day the LNG cargo arrives. In many emerging markets, it is the gas-fired power generation sector that fills this key role of anchor demand. The establishment of the LNG-based value chain in Japan and Korea in the late 1980s was founded on fuel switchable power plants. Over time, as other residential and commercial markets developed and new customers were added, the relative importance of power declined. The same will be true in China.

The role of power plants as anchor customers also enables better management of gas demand to ensure a high overall load factor. This would minimise the cost of gas supply and improve its competitiveness. LNG projects, like pipelines, are highly capital intensive, so that the unit cost of gas supply is directly correlated to the load factor. Base-load power plants and industrial customers have the highest load factors, and residential/commercial end-users the lowest. However, there are complementarities between power station and local distribution loads, which can be combined to raise the overall load factor.

Power plants are also important in that they can provide the assurance of off-take that may be difficult for distribution companies, given the less-secure projections of residential demand. This is important because of the need for long-term take-or-pay contracts with off-takers, to ensure outlets for gas and to minimise investment risk. Realistically, power generators are best placed to underpin the types of commitments required by gas suppliers and infrastructure investors. Issues related to gas-fired power generation have been discussed in more detail in Chapter 4. A critical issue that will also affect the future expansion of LNG projects in China is power sector reform, which, if not carried out appropriately, may present uncertainties and risks.

Over the longer-term, local gas distribution markets must be developed to fulfil the initial objectives of developing the gas industry, i.e., reducing environmental pollution and providing high quality fuel to the residential and commercial sectors. Gas conversion of both the existing network and appliances will be a very important task. Issues of local gas distribution were discussed in Chapter 5.

Financing

The financing of LNG-based infrastructure projects is a critical element in the development of a gas supply chain. Financing issues apply to all elements in the supply chain – from production and liquefaction through shipping, to the development of the LNG import terminal, associated distribution infrastructure and new customer facilities e.g., power plants. These issues will be discussed in Chapter 9.

The project rate of return will affect ability to finance projects. The rate of return must be compatible with the perceived risks of the project. The higher the perceived risk, the higher must be the required rate of return to support financing and provide an adequate return to investors.

The intrinsic risks involved in the development of a greenfield market and the associated customer base are high. Therefore, it is important that the risk/reward relationship of the whole supply chain is founded on secure off-take agreements with credible well-resourced gas buyers. The stronger this foundation, the stronger will be the sustainability of the whole supply chain. Increased state or provincial government support for gas will open channels to more and lower-cost sources of finance.

Sourcing of LNG

Decisions on the sourcing of gas will have to take account of several factors, notably price and supply security. Contract terms, including price, are established through negotiation around norms established through industry practice. Base price and escalation terms agreed will depend on the value of the gas in downstream markets, competition from other countries seeking LNG supplies and competition between upstream suppliers.

In a buyer's market, competition between upstream suppliers will be strong. It will reflect:

- Cost of gas at the well-head: Some suppliers may have access to cheaper gas reserves (especially associated gas with no local market and therefore low market value).
- Upstream supply cost (liquefaction and shipping). Distance from China will affect the cost of transportation (by increasing the number of tankers required).
- Whether the LNG supplier is a greenfield project or an expansion project (an additional liquefaction train).

The perceived risk of supply disruption or unreliability will depend upon technical, contractual and political assessments of the LNG supply projects and their host countries. For example, the ability of a supplier to cope with plant outages may differ between projects. Sea route will also affect supply security.

Ownership structure and contractual relationships

The degree of vertical integration along the downstream LNG chain (receiving terminal and regasification plants, transmission pipelines, power plants and distribution companies) can vary from country to country. Options include:

- Partially vertically integrated terminal/pipeline company, with back-to-back LNG purchase contract with the suppliers and long-term sales contracts with major off-takers (as for the Guangdong project).
- Integrated terminal/pipeline/local gas distribution and even power-generation company.
- Separate ownership of the import terminal/plant and pipeline project independent from both gas customers and LNG buyers.

Vertical integration is an effective means of dealing with uncertainty and risks that would be extremely difficult to manage through contracts. By reducing the number of transactions, it also reduces the value-added taxes on gas sales, thus reducing prices for end-users. In the case of an emerging gas market, where risks and uncertainties are high, an integrated model looks like the optimal structure. However, care must be taken to safeguard future needs for allowing third-party access to receiving and regasification facilities, as Japan and Korea currently plan to do.

Irrespective of the organisational model, there are a few clear legal and regulatory issues that must be in place to ensure that there is clarity for potential LNG project investors. The most important are:

- Clear procedures for the licensing of LNG projects (including supply and marketing rights covering designated supply areas) and approval of associated LNG import contracts.
- Clear and stringent technical, safety, and environmental standards.

In addition, the growth of the market will also require that the legal and regulatory frameworks surrounding other parts of the gas chain be adequately specified. The framework for local distribution companies (LDCs) and power plants are particularly critical, as they will shape the scale and profile of gas demand in the market. The following are the most important elements:

- Gas-fired power generation projects should be given priority as key anchor customers in the gas supply chain. In particular, power plant investors should be given assurance of off-take and pricing for power to underpin their gas purchase obligations.
- The LDC sector should operate under a clear framework that defines the investment, funding, pricing and franchise terms. The franchise terms for LDCs, e.g. geographical area and period of exclusivity, must be clear and must provide sufficient time and opportunity for investors to recover their investments. LDCs must be given the opportunity to raise finance (including foreign investment and municipal bonds) to sustain their expansion plans. They must also be given assurance of their ability to pass on their gas purchase costs and make a reasonable rate of return on their infrastructure investment.

On the structure side, the approach chosen for the Guandong project is an interesting one. It involves the setting up of a separate company with a minority stake taken by a state company (CNOOC in this case) to own and operate the import terminal and high-pressure transmission line, import gas on a cif (cost-insurance-freight) basis and resell the gas to large buyers.

There are several advantages to this approach that may make it the preferred model for future projects in east China. It can provide a channel for strategic guidance of the development of the gas sector by the government through participation by a state company – a crucial consideration in view of the importance of rapidly establishing a market for gas. State company involvement is also likely to reassure foreign investors and lower the cost of capital. A vertically integrated project structure is also likely to reduce investment risk and transactional complexity. Financing for projects structured this way, given the success of similarly structured projects in other countries such as Korea, is also likely to be easier than for less proven models. Decisions on the ownership structure of each LNG company will need to take account of the balance of interests in the project, technical expertise in project management, and financing considerations.

RECOMMENDATIONS

Based on the above analysis, the following recommendations are formulated:

RECOMMENDATIONS ON LNG IMPORT PROJECTS

The Chinese government should:

- Encourage development of the LNG market through structuring LNG-based gas infrastructure projects, providing incentives that promote the growth in gas demand, backing gas off-takers for their long-term purchase commitments and reducing uncertainties caused by power sector reform.
- In the context of designing an overall legal and regulatory framework for the entire natural gas industry, establish clear procedures for approval and licensing of LNG projects, with particular attention to the future needs of open access to LNG infrastructure.
- The institutional structure should allow for long-term competition between gas suppliers through open access to onshore pipelines and import terminals as the market matures, but this cannot be effectively introduced until the market is sufficiently well established. The government needs to clearly indicate its intention for third-party access to the existing LNG terminal and related facilities at a defined future date.
- Draw up and enforce appropriate technical, safety and environmental standards for LNG importation and regasification.
- Take active measures to encourage gas demand build-up in both power generation and local gas distribution sectors as discussed in Chapters 4 and 5.

FINANCING GAS INFRASTRUCTURE PROJECTS

Highlights:

- *The expansion of China's gas market implies a significant volume of capital investment in infrastructure projects. Gas infrastructure financing has a number of specific features, especially the need for balanced risk allocation among the actors in the gas chain. Gas development policies need to take into account the particular constraints that are imposed by lenders on financing gas infrastructure projects, and to allow investment return to be commensurate with the risks.*
- *The key issues concern the broadening and deepening of domestic financial markets in China, and addressing the various risks inherent in large infrastructure projects.*
- *This chapter examines the various sources of financing that could be tapped. It also analyses the specific features of gas infrastructure financing, the risks associated with this type of project, and ways of mitigating them.*

INVESTMENT NEEDS

During China's current 10th Five Year Plan (2001-2005) the State Development Planning Commission is focusing on four major natural gas projects: development of the East China Sea offshore natural gas deposits, building China's first LNG importing terminal in Guangdong province, construction of the 4,000-kilometre West-East Pipeline (WEP), and completing feasibility studies for a natural gas pipeline to bring Russian natural gas to north-east China. The WEP is estimated to cost $5-6 billion just for the pipeline; an additional investment of $3-4 billion is expected for upstream exploration and production of natural gas supplies, and a further $8-9 billion for downstream market development. While the cost of constructing the Guangdong LNG terminal and associated facilities is estimated to cost a relatively modest $600 million, it implies contracting for some $10-15 billion worth of LNG (depending upon cost and volumes) over 20 or more years. In addition, downstream investment in gas reticulation and end-use facilities, e.g. integrated combined-cycle power plants for base- and intermediate-load will be required. The Irkutsk pipeline is estimated to cost several billion dollars and would imply a purchase commitment of more than $1 billion a year, again with the need for commensurate downstream investment. As a rule of thumb, the State Development Planning Commission assumes that each additional one billion cubic metres of gas will cost about $1 billion to develop. This would imply investment needs of up to $40 billion during 2001-2005, $30-60 billion during 2006-2010, and about $80 billion or more during 2011-2020.

Table 9.1

Investment Needs for Developing China's Gas Market

	2001-05	2006-10	2010-20
Demand Increase (bcm/y)	20-40	30-60	80-100
Investment Need (US$ billion)	20-40	30-60	80-100

Clearly, the capital requirements for natural gas projects already approved by Chinese authorities are substantial. Although the amounts of investment needed are large, there are both domestic and foreign sources of debt and equity finance available.

MAJOR FINANCING SOURCES

Over the past 30 years, there have been significant changes in the world of finance in general, and in energy finance in particular. In general, the capitalisation of equity markets has grown enormously, as have the volume of equities traded, the depth and breadth of the investor base, the interconnectedness of capital markets, and—aided by technology developments—the speed at which equity and debt markets react. Energy projects over this period have moved from corporate balance sheet or government financing, where repayment is independent of the ultimate profitability of the venture, to project financing, in which the return on investors' repayment depends upon the revenues generated by the project. This is also the case for China, where corporate funds and government budget will be less and less significant compared to the volume of capital requirements for energy projects.

Potential domestic and foreign sources of finance for natural gas project investment in China are outlined below. The critical issue is not the availability of finance, but the cost of financing these investments. Since the price of delivered gas is already an issue in China (see Chapter 6), keeping the cost of investment as low as possible will keep the end-user price of gas more competitive. This can be done in part by reducing risk, but may be offset to some extent as lending moves from being policy directed to being commercially allocated. Thus, the issues concern the broadening and deepening of domestic financial markets in China and, as regards foreign capital, addressing the various risks inherent in large infrastructure projects.

Domestic sources

Citizens of China have high savings levels. Historically, these savings have gone into bank accounts or government bonds. In 1990, equity markets opened in Shanghai and Shenzhen. The long-standing habit of state-owned firms to turn to state banks for financing remains strong, despite the existence of domestic equity markets for the last decade. In 2001, Chinese enterprises raised about 100 billion RMB (US$12 billion) on equity markets, while bank loans extended to Chinese companies grew by more than 1,300 billion RMB (US$ 156.6 billion) over the same period.[1]

1 Dai Xianglong, governor of the People's Bank of China, cited in "China's Central Bank to Further Support Development of Stock Market", *China Web*, January 16, 2002.

As the leadership of China has attempted to steer from a centrally-planned economy to a market-based economy, the financial sector has lagged. Both debt and equities markets continue to be used to fund state-owned enterprises (SOEs) to carry out government policy and, more recently, to stave off potential social unrest that could accompany large enterprise failures. The leadership appears to recognise the need to address these issues and their legacies: a banking sector with substantial non-performing loans to SOEs, and a highly speculative and inefficient equities market. China's 2001 entry into the World Trade Organisation will accelerate change in the economy at large, and the financial sector in particular.

Domestic debt

The main avenue for debt financing for state-owned enterprises (SOEs) in China has been government funding through bank debt. Additional sources of funding are treasury bonds issued by the central government, financial bonds issued by state-owned policy banks (China State Development Bank, China Agriculture Development Bank, and China Import and Export Bank), and corporate bonds issued by the SOEs themselves. Total government debt issues increased from RMB19.3 billion in 1986 to RMB601.5 billion in 1999.

There are no local government or municipal government bonds in China, since local governments are not allowed to borrow on their own account. This technically removes one source of financing for the development or expansion of municipal natural gas distribution grids that is available in OECD countries either as general obligation bonds (guaranteed by the taxing power of the issuing government), or revenue bonds (dependent upon the tolls or fees collected by the project funded, i.e. project financing). Local authorities will have to rely on the central government to issue a bond for a provincial or municipal project. Although they are unable to issue local bonds, local governments and related agencies and companies often use fund collections (*jizi)* that issue papers with high rates of return to fund infrastructure such as roads and schools. While some have been successful, others have failed. Given the highly speculative and relatively undocumented nature of these instruments, it is not possible to estimate what amount might be raised through this means.

Domestic banks

Chinese domestic bank financing is likely to be the major source of funding for gas infrastructure projects, for the following reasons:

- There is strong funding capacity in Chinese banks able to participate in project finance loans. This involvement is in line with the State's objective of increasing fixed capital investment. As China develops its economy in line with its commitments to the market economy, the public utilities that currently carry out such activities as local gas distribution may become wholly or partly privatised in the coming years. This might spur development of the sector and turn these utilities from government funding toward commercial bank financing.
- As the revenues of gas infrastructure projects would be collected in RMB, which is not yet a freely convertible currency, local currency lending would minimise currency mismatch between financing costs and RMB revenues and the associated risk of a funding shortfall

in the event of unfavourable currency movements. It is also advantageous from a currency matching perspective to tap the local currency market for funds, as a large portion of the equipment for these gas infrastructure projects is expected to be sourced from within China.

- The interest rate for commercial loans is determined by the People's Bank of China on a periodic basis. The current interest rate for loans over a tenor of 5 years has been reduced to 5.76% or lower p.a., which makes local currency loans an even more competitive and attractive funding option under current market conditions.

Currently, some domestic banks can potentially offer a tenor of "construction plus 12 years" for well-structured infrastructure financings. The tenor could potentially be stretched if the project is of significant importance or the shareholders provide repayment guarantee.

In the past it has been difficult for joint venture foreign parties to raise RMB debt. On 15 July 1999, Circular 223 on "Improving the Administration of Renminbi Loans Secured by Foreign Exchange" issued by the People's Bank of China came into effect. This facilitates the raising of RMB financing by foreign-invested enterprises ("FIEs"). Specifically, Circular 223 allows the raising of foreign exchange-backed RMB loans for both working capital and fixed-asset investment from China's state-owned commercial banks. It should be noted that the loan tenors are restricted to five years, and that loans need to be supported by hard currency deposits in China, a pledge of the FIE's forex equity contribution and/or a pledge of the FIE's forex current account receivables as security. Therefore foreign investors would not face great difficulty in raising large RMB loans with suitable tenors.

Bank loans in China have been attractive due to relatively low interest rates. In addition, since country risk and foreign exchange risk are not factors in RMB loans within China, no premia are involved to mitigate these two risks for domestic loans. The debt-to-equity ratio of foreign-funded firms in China is limited by regulations promulgated in March 1987. For investments under $3 million, debt cannot exceed 30% of the total investment. The ratio rises to a limit of two-thirds of the total value for investments exceeding $60 million.

Domestic equity investment

Since the creation of the Shanghai and Shenzhen equity markets a decade ago, Chinese companies can raise equity finance through shares on these markets. The markets have been characterised by a high level of volatility and speculation. Further, the rapid run-up of prices on initial public offerings (IPOs) of firms on the Chinese bourses compared with the IPOs of Chinese firms on international equity exchanges suggests that much of the capitalisation of firms on the Chinese markets goes to secondary traders rather than the issuing corporation. This means that firms who can meet foreign equity exchange listing requirements, and who can obtain Chinese government approval for a foreign listing, are likely to raise more capital through overseas offerings, including listing on the Hong Kong exchange. Finally, up to now the vast majority of IPOs on Chinese exchanges have been for state-owned enterprises, rather than private firms.

The China Securities Regulatory Commission (CSRC[2]), with legislative authority contained in the Companies Law of 1993 and the Securities Law of 1998, has been working to reform the Chinese equity exchanges and increase their use by private companies in China. Bringing more Chinese firms, e.g. natural gas distribution companies, into reformed equities markets in China would require the firms to upgrade the quality of their financial controls and reporting. But in return, this would offer the firms an additional source of domestic capital and eventual access, if required, to foreign debt and equity markets.

Foreign sources

Foreign-invested enterprises in China may maintain foreign currency accounts in commercial banks and may borrow funds from abroad. All foreign loans must be registered with the State Administration for Foreign Exchange, which – with the People's Bank of China – regulates the flow of foreign currency into and out of China.

Multilateral funding institutions

The World Bank and the Asian Development Bank (ADB) represent sources of technical assistance and funding for natural gas development in China.

The World Bank group has several avenues for funding natural gas development. The Bank itself can lend to projects. During the 1974-1994 period, 25% of its more than US$10.5 billion in oil and gas lending was for natural gas pipeline development. The World Bank has moved away from upstream lending to focus on sector restructuring, environmental issues, natural gas infrastructure and transnational pipelines. In addition to lending funds, the Bank also assists in establishing an appropriate business climate (it is already actively working on China's Downstream Gas Sector Regulatory Framework), providing guarantees (political risk, forex convertibility and governmental contractual obligations), and participation in project financing to provide comfort for other investors and financiers. Agencies of the Bank – in addition to the lending arm and MIGA, the insurance agency – include the International Finance Corporation, which finances private investment.

In its publication, *Energy 2000: Review of the Energy Policy of the Asian Development Bank,* the ADB stated its general policy on financing gas pipelines as assisting in the implementation of trunk gas transportation pipelines to achieve economies of scale, and to promote non-discriminatory access to pipelines by all gas producers. Similarly, the ADB will assist in the installation of natural gas distribution networks when such projects are beyond the private sector capability or interest, and for projects that promote the use of compressed natural gas for urban transport. The ADB's country operational strategy for China focuses on improving economic efficiency, promoting growth to reduce poverty in poor inland provinces, and enhancing environmental protection and natural resource management. The energy sector represents nearly one-fifth of cumulative ADB lending to China, amounting to US$10.3 billion as of 31 December 2000. In specific natural gas terms, the ADB has provided a

2 A profile of the CSRC and a brief history of its regulatory actions can be found on the China Online website at http://www.chinaonline.com/refer/ministry_profiles/CSRC.asp.

US$130 million loan for the Pinghu Oil and Gas Development project in 1995, and has earmarked a US$200 million loan for a coal-bed methane demonstration project for 2003. It has also funded a number of technical assistance projects on natural gas and coal-bed methane in China. In its Country Assistance Plan for China for 2001-2003, the ADB notes that it will support private sector investments in LNG terminals and gas pipelines to provide a clean fuel alternative in China, and will consider financing infrastructure projects – including gas transportation – that involve private sector participation.

Export credit agencies

National export credit agencies will finance exports of national goods and services for foreign capital ventures. OECD examples include the Export-Import Banks of the United States and Japan, Germany's Hermes, and France's Coface. The ability of China to tap these sources of funding will depend in part on the amount of goods and services imported for natural gas projects. The SDPC estimates that two-thirds of the value of goods and services for the West-East pipeline will be provided internally, so that foreign export credit agencies would be called on mainly to finance those kinds of equipment (turbines) and services that are not currently available in China.

Export credit finance distinguishes itself from commercial bank loans by offering longer tenors at fixed and possibly more favourable interest rates over the longer term. Involvement of export credit agencies (ECAs) can also provide incentives to commercial banks to participate in non-ECA lending, due to the attractive funding opportunities they offer to such banks. Apart from lending to limited recourse project financings, ECAs will also provide funding if acceptable guarantees from sovereign level corporate or domestic banks are in place.

Trade or overseas development agencies

Agencies such as the U.S. Trade and Development Agency, the Japan International Cooperation Agency and the Canadian International Development Agency will finance feasibility studies of capital investment projects or provide technical assistance.

Foreign direct investment

In the 1990s, China led all developing countries in inward foreign direct investment (FDI). In 2000, mainland China's $41 billion of inward FDI was edged out by Hong Kong's $64 billion (compared with $20 billion in 1999), but this was skewed by unusual merger and acquisition activity in the Hong Kong telecommunication sector.[3] These figures compare with total

3 UNCTAD, *World Investment Report 2001: Promoting Linkages,* New York and Geneva, 2001.

inward FDI for all of developing Asia of $143 billion in 2000, and slightly more than $2 billion for India. Table 9.2 provides some key statistics on FDI in China.

Table 9.2

Key FDI Statistics for China

	1980	1985	1990	1995	2000
Stock of FDI (US$ billions)	6.3	10.5	24.8	137.4	346.7
Stock as % of developing countries	2.6	3	5.1	16.2	17.5
Inward FDI as % of China's GDP	3.1	3.4	7	19.6	30.9*

Source: United Nations Commission on Trade and Development (UNCTAD), *World Investment Report 2001*, Geneva, 2001.
* Data for 1999

Foreign firms can provide direct equity participation in joint ventures in Chinese natural gas projects. China has chosen BP as a partner in the Guangdong LNG receiving terminal, and a Shell-led international consortium in the West-East natural gas pipeline. In the context of constructing the West-East pipeline, initially China lifted the 49% foreign investment limit for investment in the pipeline itself, although later PetroChina decided to own 55% and share it with SINOPEC, and opened participation in municipal gas distribution in cities fed by the pipeline to foreign investment. Under new investment rules issued on 12 March 2002 by the SDPC, construction of city gas distribution grids is removed from the previous list of "prohibited areas" and is listed as one of the 75 areas for which the government is allowing limited foreign investment. This opens the door for foreign investment in gas distribution systems other than those in cities served by the West-East Pipeline. However, Chinese companies must have a controlling stake in the construction and management of city gas distribution projects. Direct foreign investment brings not only financing resources, but also technical and managerial expertise that is particularly valuable for managing major capital projects.

Foreign portfolio investment

PetroChina, China National Offshore Oil Corp. (CNOOC), and Sinopec are all listed on foreign equity exchanges, and thus can tap into international equity markets for financing. In early 2002, the market capitalisation of PetroChina's American Depository Receipts on the New York Stock Exchange exceeded $32 billion; CNOOC nearly $8 billion, and Sinopec more than $700 million.

The poor performance and lack of liquidity of "B shares" (shares reserved for foreigners that must be purchased with convertible currencies) issued on Chinese equity exchanges, compared to "A shares" (reserved for Chinese residents), has made B shares a relatively unattractive investment. In 2001, B shares were opened up to Chinese residents and share prices tended to converge with A shares. The eventual elimination of any distinction between these two share types, combined with other market and enterprise accounting reforms by the CSRC, could increase the potential of the Shanghai and Shenzhen markets to attract foreign portfolio investment for Chinese firms engaged in the natural gas business.

Examples of energy sector financing

Table 9.3 shows a few examples of previous major energy-sector project financing completed with foreign partner involvement in China. Most of these projects were financed on a limited recourse basis, since they all have long-term off-take agreements with a single contracting party in place to ensure the sufficiency of revenue to cover debt service. All of them involved foreign financing sources, since they financed their import equipment with either export credits or US dollar financing. Other gas or power projects, which involved only local sponsors, mainly utilised domestic sources of financing.

LNG terminal, large-scale natural gas grid and long-distance gas pipeline projects are at the pioneer stage in China, and similar off-take agreements as those in power or water projects may not be achieved. Their possible financing structures are discussed later in this chapter.

Table 9.3

Examples of Energy Sector Financing in China

Project	Financing Structure	Project Cost (US$ million)	Proportion of Debt Financing (%) ECAs	US$ Banks	RMB Banks	MLAs
Shandong Zhonghua Power Project (1998)	Limited recourse	2,200	21% (ECGD)	24%	55% (CCB)	–
Fujian Meizhouwan Power Project (1998)	Limited recourse	760	23% (CESCE/ COFACE)	70%	–	7% (ADB)
Guangxi Laibin B Power Project (1997)	Limited recourse	620	66% (COFACE)	34%	–	–
Hebei Tangshan Sithe Power Project (1997)	Limited recourse	174		100%		
Anhui Hefei II Power Project (1997)	Limited recourse	646	28%	21%	51%	–
Guangdong Zhuhai Power Project (1996)	Limited recourse	1,200	78% (JBIC)	15%	7% (CCB)	
Gansu Jingyuan II Power Project (1996)	Limited recourse with pre-completion guarantee	337		30%	70% (CDB/CCB)	

Source: Hong Kong Shanghai Bank Corporation (HSBC).

Note:

ECGD – Export Credits Guarantee Department
CCB – China Construction Bank
CESCE – Spanish Export Credit Agencies
COFACE – French Export Credit Agencies
ADB – Asian Development Bank
JBIC – Japan Bank for International Cooperation (formerly the Export-Import Bank of Japan)
CDB – China Development Bank

In future, Chinese banks are likely to play a very significant role in providing both US dollar and RMB financing to projects, since their current liquidity and appetite for project risk assets is very strong. The recently closed US$2.7 billion BP Sinopec Shanghai ethylene cracker complex project has the largest composition of Chinese banks in a financing of this size and nature in China. It is the first financing in China where domestic lenders comprise a majority on the US dollar side, with the Chinese banks taking 80% of the US$ commitments and all of the considerable RMB commitments as well. This is an important milestone in the development of the Chinese lending markets, and sets a template for other upcoming large-scale project financing.

COMMERCIALITY AND RISK MANAGEMENT

The most important prerequisite for financing a gas project is its commerciality. A project that makes economic sense is not necessarily financially viable. Commerciality goes beyond simply requiring an acceptable rate of return, but depends on the entire project structure. Financial structuring alone cannot transform a fundamentally uncommercial project into one that is commercial. Box 9.1 summarises the key components that make a gas project commercial.

Box 9.1

Key Components of a Commercial Gas Project

- Project return: the overall project return should be consistent with the level of risk and reward in the project.
- Alignment of interests: all participants in the project, from upstream developers to end-users, must develop a framework that ensures maximum alignment of interests. Alignment is particularly important among the key players, but it needs as far as possible to embrace other participants, such as end-users, contractors and government.
- Regulatory/contractual framework: the project requires a strong contractual basis that ensures all participants are fully committed to the project, and that agreements are enforceable through established arbitration or legal mechanisms. The regulatory framework must be transparent and stable.
- Development plan: a development plan, agreed by all participants and off-takers, is needed to ensure that downstream development is synchronized as far as possible with the upstream and midstream construction.
- Pricing: A transparent, market-based pricing mechanism that is competitive with alternative fuels over the long term. This may include re-openers. If there is significant pricing uncertainty, then higher returns are likely to be needed. Pricing can also be designed to mitigate some project risks – for instance, inclusion of foreign exchange rate component to reduce currency exposure.

- Credit strength of end-users: inadequate off-take credit can undermine project viability. Project credit will rely on the end-users' financial strength combined with take-or-pay and ship-or-pay commitments between end-users, shipper and producer. It may require government support for a time, if off-takers do not have adequate credit strength.
- Fiscal stability: the fiscal terms governing the project must be stable, with right of compensation for adverse changes, and mechanism for appeal.
- Remittance of income: the fiscal or regulatory regime must also allow for convertibility and remittance of project income into the sponsor's investment currency.
- Adequate arbitration procedure: arbitration neutrality will also be an important element for projects with international participation to resolve any potential legal dispute.

Source: IEA adapted from industry sources

All capital investment projects entail risks of various kinds. The costs of financing any capital investment project can be reduced if a risk is assumed by the party(ies) most able to control it. Unlike many other types of investment, the risks inherent in natural gas projects are attenuated because of the long-term (typically 20-25 years) nature of such projects. Specific risks related to long-distance gas pipelines are described in Box 7.2. The following text describes the types of risks involved in any large capital investment. Where applicable, mitigation measures are also analysed, with particular reference to China's gas infrastructure projects.

- ***Country risk.*** There are two kinds of country risk: portfolio diversification and asset expropriation. Portfolio diversification risk is often characterised by "country limits," i.e. the amount or percentage of investment that a given investor is willing to place in one country. Obviously, this will be influenced by the perception of the presence of other types of investment risk in the country and on past records of repayment. Asset expropriation risk, which may be magnified in countries whose governing regimes or their continuity are perceived as unstable, can be mitigated by multilateral institutions such as the World Bank's Multilateral Investment Guarantee Agency (MIGA) or national institutions.

- ***Foreign exchange risk.*** Foreign exchange risk arises when investments are made in a foreign currency while the profits of the project are in local currency, e.g. loans in Euros to a natural gas project in China that receives revenues in Renminbi (RMB). In the case of two convertible traded currencies, this risk can be hedged on foreign exchange futures markets. In the case of China, the RMB's exchange rate is set by the People's Bank of China. Since the People's Bank of China can reset or float the RMB exchange rate, risk can be mitigated by specifying that repayment be made in the currency that is invested. A related risk is the ability to repatriate profits and to be able to convert local currency profits into foreign currency for repatriation. This has been an issue in China for foreign investors. Foreign exchange risk can be mitigated by use of local loans in host-country currency, particularly if there is significant local content in the project development. This may well be an attractive option in China, where local banks appear to have considerable resources.

- ***Technical risk.*** Unforeseen technical problems could arise during project construction, leading to increased project costs and delays in completion.

- ***Completion risk.*** This is the risk that a project will not be completed in time, thus reducing the return for investors. There might be other consequences, e.g. if the Guangdong LNG terminal and associated infrastructure were not to be completed on schedule, depending upon the LNG supply contract agreed, the Guangdong LNG partners could be liable for "take-or-pay" payments for gas that cannot be received as contracted. Completion risk is generally mitigated by clauses in the engineering, procurement and construction (EPC) contracts that stipulate penalties for failure to complete on schedule. With regard to foreign investors, completion risk also can be reduced by sticking to proven technology, and using internationally recognised firms for the design, construction and management of projects, as well as the manufacture of critical equipment.

- ***Supply risk.*** The economics of natural gas projects depend, *inter alia,* on specified annual volumes of gas being delivered within specified parameters of variability, e.g. seasonal or daily. Failure to supply contracted quantities reduces the return on the investment. This applies to producers supplying pipelines, and pipeline companies supplying local distribution companies or end-users. Comprehensive agreements need to be in place to ensure the continuity of gas supply to the downstream markets throughout the life of the project. Like completion risk, this risk can be mitigated by specifying penalties for failure to deliver gas in the quantities and qualities specified in the gas supply contract.

- ***Off-take risk.*** This risk can be considered the mirror-image of supply risk, i.e. the failure to take the volumes contracted within specified time periods. This risk generally is mitigated through "take-or-pay" provisions in the supply contract, whereby a pipeline company guarantees *vis-à-vis* suppliers, or a LDC/major purchaser guarantees *vis-à-vis* suppliers/pipeline, etc. Where these entities are state-owned, it may be necessary for the guarantees to be backed by the government. An example of off-take risk can be seen in the natural gas pipeline from Shaanxi to Beijing, where natural gas demand in Beijing did not meet pipeline capacity levels even three years after the pipeline was completed.

- ***Market risk.*** The failure to accurately forecast demand or set prices may result in market risk, i.e. that market demand fails to meet contracted supply obligations. Market risks frequently cause off-take risks. Market risk is particularly high in China, where the natural gas market is still at its formative stage as the government has just started to loosen supply and price controls. Hence, there are no historical data for price and income elasticity of gas on which to base demand projections. The number and complexity of the downstream projects identified as gas buyers, and the need for each of these projects to be financed and constructed in time to take gas on completion of the gas infrastructure, is also another area of concern. Investors and lenders will need to have a very high level of confidence that buyers will be in place by the completion of the upstream and midstream infrastructures, in order to be willing to make the funding commitments required. The mitigation for these risks will be in the commercial and contractual structures adopted for the gas sales.

- ***Regulatory risk.*** Markets prefer regulatory regimes that are transparent, involve all stakeholders in a formal, open process of rulemaking, and are relatively stable. Where any of these factors is absent, only governments or their regulatory authorities can mitigate risk by addressing the elements that are lacking. If government action is not adequate, investors will attempt to compensate for the higher risk by demanding higher returns.
- ***Legal risk.*** The method of mitigation for many of the kinds of risk outlined above is defining clear responsibilities and associated penalties in the various contracts that constitute a natural gas deal. This assumes that all parties have confidence that the legal system is independent, unbiased, and professional, and that it is empowered to decide issues of commercial law and enforce legal decisions. There is some concern that although China enacted a commercial law in October 1999, particularly to conform with its accession to the World Trade Organisation, the Chinese legal system lacks judges with understanding and experience of international commercial law. With a current caseload of some 3 million contract disputes annually, the system is now gaining experience. Most contracts with foreign firms still require the approval of the government of China. It is unclear whether judgements against Chinese firms would, or could, be enforced.
- ***Credit risk***. As stated at the outset, financing costs can be minimised if each party accepts the risks that it can control. In addition, investors will look at the ability of the parties to assume their responsibilities. This is relatively easy in the case of large firms (such as PetroChina, CNOOC or Sinopec) that are listed on international equity exchanges, since these firms must supply certain information according to international accounting standards about the firm's finances. In the case of other state-owned firms, particularly provincial or township enterprises that may be relatively unknown to outside investors and whose financial reporting may be less frequent and more opaque, credit risk may be high (as rated by international rating agencies such as Moody's or Standard and Poor's) or even impossible to establish. In this case, investors will try to mitigate risk by requiring some level of sovereign government guarantee.

SPECIFICS OF FINANCING GAS INFRASTRUCTURES

Financing long-distance gas pipelines

Of the entire gas business chain, from upstream through midstream to downstream, China has placed top priority on the construction of gas infrastructure – gas pipeline construction in particular – to pave the way for the large-scale development of a natural gas industry. Foreign participation in gas pipeline construction is very much encouraged, but many foreign companies are also interested in gas exploration, production and marketing. Without being able to secure enough gas reserves and an adequate gas market, foreign companies are not eager to incur the risk of pipeline construction.

As the capital needs for a long-distance pipeline usually amount to billions of dollars, its financing is often complex, and must meet a certain number of conditions. Box 9.2 provides some typical conditions for the initial funding of a gas pipeline project in North America.

Box 9.2

Typical Conditions for Initial Funding of Pipeline Projects in North America

- Shipping contracts covering 90% or more of designed capacity;
- Reports from Independent Engineer, Insurance Advisor, Gas Market Advisor, and Supply Advisor;
- Obtaining all regulatory permits;
- Obtaining major part of the rights-of-way with a detailed plan for acquiring remaining rights;
- Signing of construction and material contracts covering 80% of estimated construction costs on a fixed-price basis;
- Equity commitment sufficient to fund a 20% capital budget overrun.

Source: Harvey L. Harmon, "Financing, Management and Pricing of the Cross-Border Gas Pipeline Projects in North America", Presentation at the US-China Oil and Gas Industry Forum, 11-12 September 2001.

Commercial structure for pipeline financing

Financing of the pipeline would very much depend on its commercial structure and the associated risk allocation through the entire gas chain. A simple commercial structure would be for the pipeline to act only as a transporter – not buying or selling gas, but just being paid fees by buyers or sellers based on the amount of gas carried by the pipeline. This would greatly reduce the risks in the pipeline venture and make financing simpler to achieve. It would also allow third parties to use the pipeline to transport gas from new gas fields, and pay the pipeline JV for transportation. This would improve the pipeline's returns for its owners in the future.

Since foreign partners are likely to look for involvement upstream and downstream to justify investing in pipelines in China, the potential commercial structure would probably have the following elements:

- The upstream and downstream parts of the partnership could be established as separate joint ventures, rather than part of the pipeline venture, to allow maximum flexibility. For example, a number of upstream and downstream ventures could be established, with different partners coming into each.
- Downstream companies could have different roles – taking market risk on buying and selling gas, or only acting as sales agents (making a margin for aggregating demand). Owners of the pipeline would prefer the latter idea, to simplify the downstream responsibilities and the financing commitments required.
- Upstream gas producers are likely to be financed by equity or guaranteed loans, as lenders are usually unwilling to take on the risks of these projects. This is likely to make them the most natural risk-takers for market demand.

- Downstream JVs would therefore attempt to identify end-users and agree long-term contracts with them for sales, and then pass that demand back upstream through long-term gas supply contracts with upstream JVs.

In this business model, downstream JVs would not agree to firm supply contracts with upstream gas producers unless they had confirmed sales contracts with end-users. The upstream parties would therefore take the final market risk, as it is unlikely that firm off-take contracts will be in place at the time gas field development has to start.

Gas transportation contracts with the pipeline JV could be made either by downstream or upstream ventures (or in the future by third parties), who would pay transportation fees to the pipeline JV. In practice, it will make little difference whether it is the upstream or downstream parties which commit to paying transportation fees, as long as they are creditworthy parties.

Financing method – limited recourse project financing versus corporate guaranteed financing

One option for the pipeline project's financial security package would be a limited-recourse project financing which relies on the project's cash flows and assets as security for the debt. In a project financing, shareholders' financial commitments would be limited as far as possible to only their equity injections. Lenders would take on the majority of project risks. The terms of repayment are often linked to a greater or lesser extent to the success of the project rather than the borrower's assets and ability to repay in general.

However, two main requirements need to be met in order to put together a limited-recourse structure for the pipeline project: first, lenders' requirements of project financing, which would include long-term gas sales contracts covering cash generation sufficient to meet debt service and other project requirements. This is unlikely to be possible for a pipeline project in which the upstream gas fields and downstream buyers are all at the development stage. In addition, a strong contractual framework will need to be established to mitigate against other risks such as construction risks, technical risks, gas supply risks and market risks. Negotiation of contracts and subsequent due diligence by the lender on the contractual structure will require a considerable amount of time and, depending on the overall project schedule, these may become critical path items. Documentation and advisory services will also add to transaction costs.

The other financing option would be a guaranteed structure in which the equity partners would each be responsible for their share of the debt, either through shareholder loans or by providing guarantees to finance raised by the JV company. The partners would each guarantee their share of the debt for the life of the loans – i.e., the debt would be "on-balance sheet" for each company, and lenders would receive unconditional guarantees from the JV shareholders, which would be called if the pipeline JV could not meet its debt repayments at any point. It is a relatively simple and expedient method of financing projects. However, it depends on the Investors/Guarantors' willingness to absorb all project risks. The amount of debt that can be raised depends on the borrowing capacity of the guarantor(s), and lenders would require restrictive covenants on the guarantors. Lenders may also seek further enhancement from parent companies or financial institutions, if the guarantors are not sufficiently strong.

Project financing for the pipeline at a later stage should still be considered, however. It is also possible to construct hybrid structures, in which, for example, a guaranteed financing converts to a limited-recourse structure at a given point. The debt could be refinanced under a limited-recourse structure when construction has been completed, and after a successful period of pipeline operation and gas sales.

Financing LNG receiving and regasification terminals

The major links in the LNG chain include: LNG exploration, liquefaction, shipping, receiving and regasification terminal, distribution of the regasified LNG and finally, consumption of the gas. Each element of the LNG chain which links the natural gas in the ground to end-users has to be carefully structured. Extreme reliability in each component of the LNG chain is essential, because if any one component of the chain is out of action it cannot be easily replaced. Lenders to projects in each link of the chain rely on cash flow, which is based on the successful operation of each element of the LNG chain, starting with gas sales.

The success of LNG projects requires each element of the chain to be successfully delivered, which include development of the following:

- long-term gas sales contracts with major off-taker(s);
- successful construction of the LNG receiving terminal and pipelines, including financing;
- long-term charter agreement for LNG transportation; and
- long-term gas supply/liquefaction contract with reputable supplier(s).

The developer of the LNG regasification terminal would have to ensure that, from the very beginning of the development process, all contractual relationships for the LNG chain have been designed and structured in a way that allocates risks to the best assuming parties which will then enable the raising of limited recourse financing at a later stage.

If the LNG regasification terminal is going to raise limited recourse financing, it will be the LNG terminal sponsors' objective to have creditable buyers take deliveries of LNG on a long-term basis and at an optimal level that will enable the LNG terminal to cover a certain percentage of annual debt service. Some detailed commercial arrangements, including the incorporation of downward flexibility, the requirement to "make good" the quantities not taken within a certain period of time, the mechanism in the case of "force majeure" will need to be fully defined in the contract to provide a protection mechanism to both buyers and sellers as well as to lenders.

The question of how to structure the LNG supply and gas sales contracts in order to minimise retained risks in the project, and ensure that the supply contract is backed up by sufficiently creditworthy counterparties, will be crucial to delivering an economical and bankable project.

The terminal JV company will stand in the middle of a "chain" of related projects in which the end-gas buyers provide cash flow to support each of the other links in the chain – the terminal and trunkline company, LNG shipping company, the liquefaction plant, and upstream gas producers. This "chain" of cash flows creates a series of payment risks from one part of the chain to the next.

As the terminal JV company in China will normally be a leveraged, special purpose vehicle company, with its sole asset being the terminal and trunklines themselves, it may not be appropriate for this company to act as risk-taker on the gas purchase obligations. The terminal JV company will not be capitalised enough to take the entire risk of paying the LNG cost to the upstream LNG suppliers in the event that the downstream customers do not pay. The rate it charges for regasification and transmission is a small percentage of the entire gas price charged to the final downstream customers. Upstream LNG suppliers, who usually have a better balance sheet, will need to share the credit risk. On the whole, LNG projects can work only when the risks are well balanced between upstream and downstream players.

On the LNG transportation side, the Chinese government's objective seems to be that domestic shipyards start to construct LNG vessels in China with technology transferred from foreign shipyards, and to have domestic shipping companies, together with experienced foreign shipping companies, provide LNG shipping services to the LNG terminal. The domestic and foreign shipping companies will form LNG transportation JV which will charter transportation on a Free-on-Board (fob) basis, meaning that the LNG purchasers arrange LNG transportation. This will create additional flexibility in sourcing supplies, through spot markets or short-term contracts where competitive, and Chinese sponsors can gain experience in and control over the LNG transportation business.

Given the huge costs required for LNG vessel construction and the absence of an ongoing spot market in LNG, few vessels have been built on speculation and most fleets are specially designed for a specific trade for which they ensure continuity of supply. Lenders to the vessel would therefore require a long-term charter party for LNG carriage to provide long-term financing. The LNG terminal, in turn, needs to have a long-term LNG supply contract to support the charter party. In addition, it is necessary to have an experienced ship-operating entity that is capable of satisfying the obligations under the charter party and complying with the rules and regulations of relevant national and international regulatory bodies.

Financing urban gas distribution systems

Urban gas distribution systems involve investment in the city gas trunklines and distribution network. The scale of investment will depend on the area covered. The distribution grids for natural gas will be either newly built, or converted from the existing coal gas pipelines in the area. Main customers will include a large number of individual household users, commercial and public buildings, and industrial customers. Hence, investment will also need to cover billing, marketing, customer management systems and service systems for multiple customer utilities. As such, it takes time to build the gas markets and implement fuel conversion for customers. Investment in these networks may continue for many years as the network is further expanded, which is quite different from greenfield projects like power plants.

As a consequence, the financing of urban gas distribution systems will also be required for a longer period, as expansion continues. Multiple small users and the lack of long-term gas sales contracts may make project financing difficult to achieve. Therefore, lenders will usually require more support from sponsors, and are concerned in the rate of successful customer build up. The rate of availability of funding will depend on the performance of gas suppliers in securing new customers.

The restrictions on local and municipal governments to issue bonds have limited their ability to fund urban gas distribution projects. They can, however, continue to use their traditional method of fund collection (jizi). In addition, local or municipal governments can provide direct funding from tax revenues for a project. Local and township enterprises can fund projects from their revenues. Finally, government authorities at both the national and local levels can support local gas distribution and marketing companies through fiscal terms, i.e. tax reductions.

Financing large end-use projects

Gas-fired power plants are the largest and most stable gas consumers. They should be targeted as the major consumer base at the early stage of gas infrastructure operation. Other large gas end-users include chemical plants, refineries, and metallurgical plants.

In China, the main focus has been on developing coal-fired, hydropower, and nuclear power plants. Typically, investment in these large-scale, end-use projects concentrate on the first 2-4 years of construction, and maintenance expenditure will be required throughout the operating period. The fuel risk of these projects is less than that of gas-fired power plants, since the gas source in China is still at the development stage.

Lenders will require power plants to show promising demand for power from the operating region. In a limited recourse project financing, lenders will require long-term electricity off-take contracts to be in place throughout the tenor of the loan, in order to generate sufficient cash flow for debt service. Gas price will normally be required to flow through to the final electricity price. Gas supplier(s) will also require long-term take-or-pay gas purchase contracts to be in place with the power plants.

On the other hand, to date, no large-scale petrochemical or refinery projects in China have been financed on a limited recourse basis. Petrochemical products are available in a variety of forms and therefore sold to various customers. Since long-term sales contracts may not be available for these products, these projects usually suffer from market volume risk. As a consequence, the gas supply to these projects will also be subject to product volume risk. Petrochemical products will largely be sold, and feedstock purchased, at international prices. Appropriate financial structures will need to be designed to accommodate the expected cyclical price behaviour of feedstock and products.

Limited recourse financing for petrochemical projects is achievable if lenders can get extra comfort from the project sponsors by getting contingent cash flow shortfall support during the early market build-up period. The amount and level of support will depend on the product off-take level.

CONCLUSIONS AND RECOMMENDATIONS

Although China will require tens of billions of dollars for natural gas development during the current decade, it is confident that there are sufficient financial resources available, both domestic and international. The key issue is how to create the necessary conditions to channel the available resources to finance concrete gas projects with the lowest cost. In defining gas development policies, China's policy-makers will need to take into account the specific characteristics of gas infrastructure financing, respect lenders' constraints, lower the risks they run in participating in gas infrastructure development, thereby reducing the cost of financing.

During the 1990s, China made reforms in both its banking and financial systems generally, and to the level of professional management of state corporations, including their financial management and reporting. The most obvious results of these efforts in the oil and gas sector were the listing on international stock exchanges by PetroChina, Sinopec and CNOOC. Further reforms to domestic debt and equity markets will expand the availability of lower-cost domestic capital for companies involved in all levels of the natural gas industry.

A key to the successful expansion of China's natural gas market will be making gas competitive. This, in turn, requires that the cost of capital be reduced by managing the various risks associated with natural gas projects—upstream exploration and development, LNG and pipeline import projects, domestic pipelines, urban gas distribution systems, major gas consumption projects, and development of a gas appliance industry.

To facilitate gas infrastructure financing, increase the availability of financial resources, and reduce the cost of capital, the following recommendations are formulated:

RECOMMENDATIONS ON GAS INFRASTRUCTURE FINANCING

The Chinese government should:

- Create conditions that would facilitate the financing closure of gas infrastructure projects and take active measures to help investors reduce investment risks. This could include, but not be limited to:
  - Providing some sort of credit backing to downstream off-takers to make sure that they will honour long-term off-take agreements, in order to enhance the bankability of the whole gas chain from upstream exploration to midstream transportation.
  - Recognising the environmental benefits of gas, providing subsidies, preferential tax exemptions or preferential land lease fees to gas infrastructure ventures, so that they can offer a competitive gas price relative to other sources of fuel to improve their economic sustainability and help gas market growth.
  - Accelerating full convertibility of the RMB.
  - Considering subsidising interest rates on key natural gas projects until Chinese companies and the market are sufficiently developed to attract project financing on a purely commercial basis.

- Increase the availability of domestic financing resources. This could include:
  - Creating a national, uniform regulatory system to create and regulate a municipal bond market.
  - Continuing to broaden and deepen the banking system reform to allocate lending on a commercial rather than political basis.
  - Continuing efforts by the China Securities Regulatory Commission to make domestic equities markets an attractive source for financing. These might include eliminating the distinction between "A" and "B" shares, bringing more institutional investors into a market that is currently dominated by individual investors, and bringing listing standards into line with international norms.
- Pay attention to the regulatory implications of the commercial structure of any large gas infrastructure projects.

POLICIES AND REGULATIONS ON FOREIGN INVESTMENT IN CHINA'S NATURAL GAS SECTOR

Highlights:

- *With its latest revision of the guidelines and catalogue for foreign investment, China has expanded the scope for foreign investment in the natural gas sector. Foreign investment is permitted in gas distribution and is encouraged in gas E&P and transportation sectors.*
- *Putting aside this positive development, China still lacks a consistent approach to foreign investment in the natural gas industry. Current practice is based on a "project-by-project" approach. There is a real need to define a gas investment policy as part of the country's long-term gas policy.*

Since the early 1980s, China has adopted an open-door policy to attract foreign investment. According to the SDPC, attracting foreign direct investment (FDI) into the country fulfils the following purposes:

- to enhance the technical skills of its workforce;
- to gain access to foreign management skills;
- to increase the amount of capital available;
- to shed some of the investment risk;
- to introduce competition to the incumbent player; and
- to gain access to foreign technology.

Over the last two decades, China has led developing countries in attracting foreign direct investment (see Table 9.2).

The distribution of FDI has been uneven across Chinese regions. The relatively prosperous eastern coastal region accounted for 88% of the country's total FDI during the period 1978 to 1999, while the central region attracted 9% and the western region the remaining share of the total FDI inflow. As part of the government's programme to develop the central and western regions, today FDI is very much encouraged to go further inland.

LAWS AND REGULATIONS ON FOREIGN INVESTMENT IN CHINA

Foreign investment in China usually takes one of the following three forms:

- An equity joint venture.
- A co-operative or contractual joint venture.
- A wholly foreign-owned enterprise.

Foreign investment in China is regulated by the following set of laws and regulations:

- The Law on Sino-Foreign Equity Joint Venture Companies (1979 and its 1990 amendments) and regulations on its implementation (1983);

- The Law on Sino-Foreign Co-operative Joint Venture Companies (1988) and regulations on its implementation (1995);
- The Law on Wholly Foreign-funded Enterprises (1986) and regulations on its implementation (1990);
- Other laws and regulations governing income tax, accounting, and mergers and separations of joint venture or foreign-funded enterprises.

Two particular documents play a very important role in determining the areas in which foreign companies can invest. They are:

- The *Interim Guidelines on the Direction of Foreign Investment*, published by the State Council in 1995 and revised as *Guidelines on the Direction of Foreign Investment*, which were published in February 2002 and became effective on 1st April 2002.
- The *Catalogue Guiding Foreign Investment in Chinese Industries,* which was jointly published by the SDPC, the SETC and the MOFTEC in accordance with State Council's guidelines. The first catalogue, based on the 1995 interim guidelines, was published in 1997, and a revised version, based on the revamped guidelines, was published in March 2002 and became effective on 1st April 2002.

These guidelines and catalogue are supposed to channel foreign investment into areas in a way that would be consistent with the overall plan for the country's economic and social development.

The guidelines and catalogue on foreign investment

The Guidelines on the Direction of Foreign Investment grouped the areas of foreign investment into four categories: Encouraged, Restricted, Prohibited and Permitted. The 1995 interim guidelines further divided the "Restricted" category into two sub-categories (A and B, for which the project approval procedure differs) according to the industrial policies and the need for macroeconomic control of the state at that time. This subdivision disappeared in the 2002 version.

Only industries that belong to the categories of Encouraged, Restricted or Prohibited are listed in the *Catalogue Guiding Foreign Investment in Chinese Industries*. This means that any industry that is not listed in the catalogue is permitted. Box 10.1 provides the criteria used to group industries into the three categories listed in the Catalogue.

Article 9 of the 2002 Guidelines states that those investment projects that fall into the category of "encouraged" will enjoy preferential terms[1] as defined by relevant laws and regulations. This could imply, for example, that income tax will be levied at 15% instead of the usual 33% for the period 2001 to 2010. Article 9 also stipulates that those investment projects that are engaged in the construction and operation of infrastructure facilities related to energy, transportation and urban infrastructure (coal, oil, natural gas, electric power, railways, roads, port, airports, urban roads, waste water and municipal waste treatment facilities), which need a large amount of investment and a long pay-off period, will be allowed to expand their business scope upon approval.

1 Over the last two decades, the Chinese government has been using preferential tax treatments to attract foreign investments. Those incentives vary according to the geographical area (e.g. special economic zones, high and new technology zones, etc.) and the nature of business activity (machinery, energy, harbour or wharf construction, etc.). Income tax exemption/reduction and tax refund on reinvestment are typical types of incentives. The OECD recommended a comprehensive review of these incentives. For more details, see OECD, 2002, *China in the World Economy*, pp. 633-634.

Box 10.1

Criteria for Directing Foreign Investment in China

As described in the *Guidelines on the Direction of Foreign Investment*, published by the State Council on 11 February 2002:

Encouraged:

- Projects for new agricultural technology and comprehensive agricultural development and for energy, transportation and key raw materials;
- Projects of new and high technology, of advanced and suitable technology, and those which can improve product performance, increase technical and economic efficiency of enterprises or produce new equipment or new materials for which domestic production capacity is deficient;
- Projects that can respond to market demand, upgrade product quality, develop new markets or improve international competitiveness;
- Projects that adopt new technology and new equipment, save energy and raw materials, promote the comprehensive utilisation of resources and renewable resources, or prevent and treat environmental pollution;
- Projects that can make full use of the manpower and resources in central and western regions and that are in accordance with the state's industrial policies.

Restricted:

- Projects that employ outdated technologies;
- Projects that are not good for saving resources and improving the environment;
- Projects that fall into the categories of special mineral resources that are under state protection for exploration or mining;
- Projects involving industries that are set for gradual opening to foreign investment;
- Other projects that are restricted by laws and administrative regulations.

Prohibited:

- Projects that endanger national security or cause damage to social and public interests;
- Projects that pollute the environment, destroy natural resources or have an adverse impact on human health;
- Projects that occupy large areas of arable land, or are not compatible with the protection and development of land resources;
- Projects that endanger the safety of military facilities and their operational performance;
- Projects that utilise the country's unique craftsmanship or techniques to make products;
- Other projects that are prohibited by laws and administrative regulations.

Permitted:

All activities that are not listed under the categories of encouraged, restricted and prohibited are permitted.

The most important area of change between the 2002 Guidelines and the 1995 provisional ones is the criteria for the category of “restricted” industries. Indeed, the 1995 provisional guidelines listed in the “restricted” category those industries for which the country already has the technology to meet demand, which are being used as pilot areas for foreign investment, or which fall under government central planning. These criteria were very different from the current ones listed in Box 10.1. Also, in the 2002 version, the “restricted” category is no longer subdivided into “Restricted A” and “Restricted B”. What remains essentially the same for the “encourage” category is the inclusion of new agricultural technology, transportation, energy and new material industries, reflecting the government’s continuing wish to attract foreign investment in those areas.

A comparison between the provisions for energy sector activities in the 1997 and the 2002 Catalogues is provided in Table 10.1. It can be seen that the list of “encouraged” areas became longer while those of “restricted” or “prohibited” much shorter. Also worthy of note are the following significant changes that are very relevant to foreign investment in the natural gas sector:

- Oil and gas risk exploration and development and exploration of low permeability oil and gas fields are now listed in the “encouraged” category, whereas they were not listed in the 1997 Catalogue.
- Large gas turbines and CCGT equipment of above 100 MW are listed in the “encouraged” category, as are the construction and operation of gas-fired power stations and CHP plants.
- Building and operation of urban gas distribution systems, which belonged to the “prohibited” category in the 1997 Catalogue, are now listed as “restricted” and require the Chinese party to hold the majority stake.
- Construction and management of oil and gas transportation pipelines, as well as oil depots and wharves, still remain in the category of “encouraged”, but the constraint for the Chinese party to be the majority holder or dominant player has disappeared.

According to the SDPC, the new foreign investment guidelines were tailored to the commitments China had made to the World Trade Organisation (WTO). Compared with the old guidelines, more investment opportunities are provided for foreign investment, as the list of prohibited areas became shorter and that of “encouraged” or “permitted” longer. The Annex to the 2002 Catalogue, in particular, sets timetables for gradually opening some “restricted” areas for foreign investment in a way consistent with the WTO commitment. A renewed emphasis is put on investment in western regions, with preferential taxation policies.

In addition, the government also encourages foreign investment in the key state-owned enterprises (SOEs). The government is planning to sell a certain amount of SOE shares over the next five years to speed up the SOE reform, and foreign investors are permitted not only to become shareholders, but also have the possibility of taking the controlling stake in some large SOEs.

Table 10.1

Comparison of Catalogues (1997 vs. 2002) for Foreign Investment in China's Energy Sector

	1997 Catalogue	2002 Catalogue
"Encouraged"	**Oil & Gas industry** ▪ Construction and management of oil and gas pipelines, oil and gas storage facilities and dedicated oil docks. ▪ Development and utilisation of tertiary oil recovery technology. **Coal industry** ▪ Design and manufacture of coal mining, transportation and selection equipment. ▪ Coal washing and dressing. ▪ Coal-water production and coal liquefaction. ▪ Comprehensive development and utilisation of coal. ▪ Pipeline transportation of coal. ▪ Exploration and development of coal-bed methane. **Electrical power industry** ▪ Construction and management of thermal power stations with a single unit installed capacity of 300 MW or over. ▪ Construction and management of hydropower stations with the main purpose of generating power. ▪ Construction and management of nuclear power stations. ▪ Construction and management of power stations using clean-coal technology. ▪ Construction and management of power stations with sources including solar, wind, magnetic, geothermal, tidal and biomass energy. **New and emerging industries** ▪ Marine energy development technology. ▪ Development of energy-saving technology. ▪ Technology for recycling and comprehensive utilisation of resources.	**Oil & Gas industry** ▪ Oil and gas risk exploration and development. ▪ Exploration of low permeability oil and gas fields. ▪ Development and utilisation of crude oil recovery technology. ▪ Construction and management of oil and gas pipelines, oil and gas storage facilities and dedicated oil docks. ▪ Development and utilisation of exploration & development technologies of drilling, testing, and underground operation. **Coal industry** ▪ Development and utilisation of clean-coal technologies and products. ▪ Construction and management of pipeline transportation facilities of coal. ▪ Exploration and development of coal-bed methane. **Electrical power industry** ▪ Construction and management of thermal power stations with a single unit installed capacity of 300 MW or over. ▪ Construction and management of power stations using clean-coal technology. ▪ Construction and management of natural gas power stations. ▪ Construction and management of hydropower stations with the main purpose of generating power. ▪ Construction and management of nuclear power stations. ▪ Construction and management of power stations with new energy sources including solar, wind, magnetic, geothermal, tidal and biomass energy. **Electro-mechanical manufacturing industry** ▪ Thermal power equipment: manufacture of super critical units and large gas turbines (>=600 MW); CCGT, IGCC, PFBC (≥ 100 MW); and air-cooled large scale units (≥600 MW). ▪ Manufacture of power plant desulphurisation equipment. ▪ Manufacture of hydropower units with large-scale pump storage (≥150 MW) and large-scale run-stream turbine units (≥150 MW). ▪ Manufacture of nuclear power units (≥ 600 MW). ▪ Manufacture of super high voltage DC power transmission and transforming equipment (≥500 KV).

"Restricted"	**List A** ■ Oil refineries with output capacity of less than 5 mt per year. ■ Gasoline stations (Limited to projects related to super highways). ■ Manufacturing of diesel generators. **List B** ■ Construction and management of conventional coal-fired plants with a single unit capacity of less than 300 MW (with the exception of small power grids, plants in remote areas, and plants using low-quality coal and coal-stone). ■ Manufacture of power generation units in excess of 100 MW including CCGT, CFBC, IGCC, PFBC, de-sulphurisation and de-nitrification equipment. ■ Manufacture of hydro-electric generating units with a wheel diameter over 5 metres, large-scale pump storage units over 50 MW, large-scale run-stream turbines (≥ 10 MW). ■ Manufacture of nuclear power units (≥ 600 MW). ■ Manufacture of large-scale transformers of 200 KV or over, high-voltage switches, mutual inductors, and cable equipment.	■ Construction and management of oil refineries. ■ Construction and management of the urban networks for gas, heat, water supply and discharge (Chinese side holding majority). ■ Construction and management of conventional coal-fired plants with a single unit capacity of less than 300 MW. ■ Wholesale of oil products and construction and management of petrol stations.
"Prohibited"	■ Construction and management of power grids. ■ Construction and management of the urban networks for gas, heat, water supply and discharge.	■ Construction and management of power grids.

Investment approval process

Foreign investment projects, just like domestic ones, are subject to government approval. The approval for specific foreign investment projects is governed by two criteria:

- A level of investment below which the approval of central government is not required (i.e. the province has the delegated authority).
- A level of investment above which the approval of highest authority of government, the State Council, is required.

At present, these two levels are US$30 million and US$100 million respectively. Projects involving capital investment of less than US$30 million do not require central government approval. Projects in excess of US$100 million need the agreement of the State Council. Those in between require approval of either the SDPC – if the project is a greenfield one, or the SETC, if the project involves the extension or renovation of existing facilities. The Ministry of Foreign Trade and Economic Co-operation (MOFTEC) is also involved in project approvals.

Thus, in effect, any significant energy investment involving a foreign party goes to the highest authority in the country.

The approval route for domestic investment projects is the same, except that the MOFTEC is no longer involved, but the thresholds change considerably, to RMB30 million and RMB 100 million. That is, the SDPC or SETC approves a project involving investments between

RMB30 million and RMB100 million. For investments in excess of RMB100 million, it is the State Council that has the approval right.

Recognising the shortcomings of this approval process, the government is in the process of elaborating new measures for project examination and approval in order to improve the quality and efficiency of decisions.

The freedom to convert local currency to foreign currency is a key requirement for any foreign investment in China. Through its State Foreign Exchange Control Bureau, the People's Bank of China has the authority to exercise control over foreign exchanges. The Regulations on Foreign Exchange Control issued in January 1996 allowed current account convertibility for foreign investors. Capital account convertibility is not yet allowed, except in the case where a foreign company terminates its operations in China.

WTO and regulatory changes

The three legal obligations of the WTO trade agreements that will affect foreign investment in China are national treatment, quantitative restrictions, and transparency. Another major WTO requisite is the institution of dispute resolution mechanisms. All these are likely to alter the foreign investment environment in China in a significant way.

To fulfil China's commitments under the WTO agreement, the central administrations in Beijing are reportedly busy checking and revising thousands of laws and regulations to remove any inconsistency with the WTO principles.

Notable among these regulatory changes are the two amendments made to the three laws on foreign investment. They concern: 1) the abolition of the requirement that all Sino-foreign joint ventures and foreign-funded enterprises balance their foreign exchange account: 2) the abolition of the requirement that all joint ventures and foreign-funded enterprises give top priority to Chinese indigenous suppliers for purchasing production materials and feedstock.

The second amendment may not affect foreign investors too much, since most of them have already localised their material supplies and staff hiring to reduce costs. But the first amendment represents significant progress for many foreign investors in the downstream oil sector. Foreign investors in China's oil industry, whether in the form of upstream joint-ventures, wholly-owned refineries, or petrochemical business, are no longer required to sell significant portions or all of their products on international markets, just to meet the government's strict policy for balancing foreign exchange receipts and expenditures.

Tax policies that are incompatible with WTO principles, in particular those tax incentives that are designed to encourage exports from China and to protect specific domestic goods, will have to be removed. Also, the different upstream fiscal regimes between domestic and foreign companies (see Chapter 6) are likely to merge under the WTO principle of national treatment.

FOREIGN INVESTMENT IN CHINA'S GAS SECTOR

China first opened its oil and gas sector to foreign investment in offshore exploration and production areas in the early 1980s, then gradually moved to onshore E&P, refinery and petrochemicals. According to the government, gaining access to foreign technology, increasing the amount of capital available, and shedding some of the investment risks are the main drivers for attracting foreign investment in the natural gas sector.

The 2002 foreign investment Catalogue opened the whole gas chain to foreign investment. This is in line with the government's desire to develop the country's natural gas market. However, there is no specific law on natural gas, and the government is studying the possibility of issuing a law that would govern the midstream and downstream gas sectors.

Gas exploration and production

Natural gas is generally associated to oil in terms of regulations. As already listed in Chapter 2, upstream oil and gas activities in China are governed by the following law and regulations:

- "Mineral resources law" of 1986 and its 1996 amendments.
- "Rules for the implementation of the Mineral Resources Law", promulgated in 1996;
- "Regulations on registration over mineral resource exploration", "Regulations on registration over mineral resource exploitation" and "Regulations on transfer of exploration and mining rights". All these regulations were promulgated by the State Council in 1998.
- "Regulations concerning the exploitation of *offshore* petroleum resources in co-operation with foreign enterprises", promulgated by the State Council in January 1982 and revised in October 2001.
- "Regulations concerning the exploitation of *onshore* petroleum resources in co-operation with foreign enterprises", promulgated by the State Council in October 1993 and revised in October 2001.
- Local laws and regulations by provinces, autonomous regions and large municipalities that are directly under the central government.
- Furthermore, there are some special regulations by the Ministry of Land and Natural Resources on oil and gas management. They concern registration, licence, penalty, notification, etc.

A summary of these can be found in Annex II of this report.

As part of the supporting policies for western regional development, the Ministry of Land and Natural Resources and the Ministry of Finance jointly issued *Measures on Reduction and Exemption of Exploration/Mining Right User's Fees or Royalties* in June 2000. Article III of the Measures stipulates that fees or royalties for the use of exploration and mining rights may be reduced or exempted (according to the scale set in Table 10.2). To benefit from these reductions and exemptions, the activities must take place in the western regions, remote and poorly-developed areas or certain maritime spaces determined by the State Council. The eligible activities include:

- Exploration and development of mineral resources in short supply.
- Exploration and development conducted by large/medium mining enterprises for alternative resources.
- Development of mineral resources utilising new techniques and methods to improve comprehensive utilisation.
- Other situations certified by the Ministry of Land and Natural Resources and the Ministry of Finance.

Those measures are likely to apply to the upstream activities of the west to east gas pipeline project.

Table 10.2

Provisions for Reduction and Exemption of the Fees for the Use of Exploration and Mining Rights

	For Exploration Activities						
Year	1	2	3	4	5	6	7
Reduction		50%	50%	25%	25%	25%	25%
Exemption	100%						

	For Mining and Production Activities							
Year	0	1	2	3	4	5	6	7
Reduction			50%	50%	25%	25%	25%	25%
Exemption	100%	100%						

Pipelines

The 2002 Catalogue listed gas pipelines as an "encouraged" area for foreign investment and removed the previous requirement for the Chinese parties to hold the majority stake. This means in theory that foreign companies can own up to 100% of any pipeline construction and management. In reality, however, no foreign company is likely to go it alone.

Although China has built a number of pipelines in recent years, all with foreign assistance in one way or another, the West-East Pipeline is the first major pipeline project that is widely publicised as a pilot project for Sino-foreign co-operation in pipeline building and management. This is discussed in more detail in the next section of this chapter.

LNG facilities

LNG receiving and gasification terminals are not listed in the 2002 Catalogue, so this is considered an area in which foreign investment is permitted. The reason for not listing this in the "encouraged" category may be due to the fact that there is no consensus among the Chinese leaders on the necessity to import large quantities of LNG. Indeed, it took about ten years for the government to take a formal decision to go ahead with the Guangdong LNG terminal, and the government still considers that terminal to be a pilot case, based on which a pronounced policy could be formulated.

Although Guangdong is still in its trial period, CNOOC has already signed an agreement with the provincial authorities to build an LNG terminal of between 3-5 million tons in Fujian. It also envisages building LNG terminals in other coastal provinces of Zhejiang, Shanghai and Shandong.

Gas distribution and consumption facilities

Gas distribution is a major area of concern for potential foreign investment, not because it still requires the Chinese parties to hold the majority stake, but because of the conditions which foreign companies will find in the distribution business. In general, there is not enough attention paid to the development of the distribution market. As a result, policy and investment have focused on upstream production and midstream transmission activities, with little effort in the downstream distribution sector.

Now that distribution is open to foreign investment, there is a strong possibility that an international distribution company will form a Joint-Venture with a well established local partner in one city and then replicate the successful experience with the same partner or others to expand into other cities.

On gas consumption facilities, gas turbine and CCGT plants are already listed in the "encouraged" category for foreign investment. In addition, the government announced that it would support the substitution of natural gas for oil, and the development of main natural gas end-uses. Concrete forms of support could be preferential tax rates to developers, or guaranteed gas tariff and power off-take contracts for gas-fired plants. In addition to central government's support, certain cities already require all new residential buildings to incorporate pipeline connections as part of their design as a precondition for construction permits. Some also decided to prohibit any new construction of coal or oil-fired power plants and to retire the old, inefficient oil and coal-fired plants in order to make room for new gas-fired generation capacity.

SPECIAL POLICIES FOR FOREIGN INVESTMENT IN THE WEST-EAST PIPELINE PROJECT

To attract foreign investment in the construction and management of the West-East gas pipeline, the government has announced the following co-operation principles:

- Opening the whole line and all of its parts. Both pipeline construction and the downstream city network are open to foreign investment. For upstream gas exploration and production in Tarim basin, PetroChina has been empowered to negotiate with foreign investors on specific terms.

- Foreign investors are allowed to be the holding party of the pipeline project.
- No restriction on the form of foreign participation: all forms are allowed.

Forming part of the western regional development campaign, the West-East Pipeline project is entitled to a number of preferential policies on infrastructure construction made by the state in the context of this campaign[2]. As it belongs to the "encouraged" category, the pipeline project can also benefit from the preferential treatments for projects of that category. Moreover, in accordance with Article 8 of the investment guidelines, the pipeline project is entitled to apply for the expansion of business scope.

The government has also announced the following specific policy measures for the pipeline:

- Tax exemption for imported equipment for the construction of the West-East pipeline;
- The pipeline will benefit from VAT and duty exemption when equipment is imported under loans from foreign investors.
- Reduction and exemption of prospecting right fees and royalties, as stipulated in the joint "Measures" promulgated by the MLNR and MOF.
- The MLNR will pursue the policy of "special project for special treatment" to accelerate the land acquisition procedure.

CONCLUSIONS AND RECOMMENDATIONS

Still at an early stage of development, China's natural gas market holds significant potential, and foreign investment can play an important role in realising this potential. International players are potential sources of capital, technology, know-how and managerial skills, all of which are essential to the successful implementation of large-scale commercial gas projects in China.

The revision of the guidelines and catalogue for foreign investment represents a welcome development in China, but more can be done. To further attract foreign investment in the country's gas sector, China needs to address a number of important concerns of international investors. First of all, a good investment environment needs to respect the commercial principles based on which all international companies function. These principles include:

- *Long-term legal and fiscal stability*: Foreign companies looking to make large-scale investments in China's gas market will be most concerned about the long-term stability of their investments. In this regard, ensuring that the legal and fiscal framework will remain constant over the life of the investment is absolutely critical. Long-term stability is essential to develop investor confidence and such confidence is necessary to ensure that the large, up-front capital investments required for new gas infrastructure projects will be made.
- *Freedom in commercial decision-making*: Companies wishing to build, own and/or operate gas infrastructure should be allowed to make commercial decisions themselves; the

2 In 2000, the State Council issued a Circular on "Policies and Measures for Western Regional Development". In August 2001, the State Council's Western Regional Development Office issued a document on the "Implementation of the Policies and Measures for Western Regional Development". This document included a very detailed list of measures that are aimed at attracting foreign investment into the defined region.

government should focus on safety and environmental safeguards. In this respect, the project approval process in China needs to be revamped.

- *Administration neutrality*: Companies need to be reassured in concrete terms that the administration of laws, regulations and dispute resolution will be conducted in a non-discriminatory manner.
- *Trade Freedom*: They need to make sure that they can market their products, without government intervention to allocate their output at a fixed price.
- *Absence of political intervention*: They wish that all negotiations be conducted on a commercial basis, without actual or threatened regulatory intervention.
- *Contract sanctity*: They require that the sanctity of commercial contracts be respected over the lifetime of the contracts, which is necessarily long.
- *Market-based pricing*: They can operate efficiently only when all prices, both for natural gas as well as its alternatives, are market-based in such a way that gas has a long-term future in the final consumer market.
- *Regulatory transparency*: They also require that the entire regulatory process needs to be transparent to all industry participants. Prices and their determination methodologies for services like terminal charges, pipeline transportation and storage, need to be published in order to ensure non-discriminatory practices.
- *Capital account convertibility*: Companies desire to retain control of capital so that it may be optimised from a company perspective. Restricting the flow of capital out of a country places a restriction on a company's ability to optimise its capital, which indirectly deters companies from investing capital into the country.
- *Indirect taxes*: To attract foreign investment, capital-intensive projects should not be subjected to indirect taxation. Although tax exemption for imported equipment for the construction of the West-East pipeline is a significant improvement, tax exemption should apply to domestically produced goods as well. Tax incentives should be structured in such a way that all international investors will benefit, considering their home country tax regimes.

Second, the government needs to go beyond the project-by-project approach and develop a coherent policy and regulatory framework for private and foreign investment in the gas sector. The project-by-project approach, which is a very important feature of China's gas investment policy, has a number of drawbacks that often leave investors in the dark. This approach also leads to the heavy involvement of government authorities in project management, rather than in policy-making and regulation. In any case, there will be too many projects for the government to manage if it continues the current practice. This could cause considerable delays in gas market development, as government resources are limited and numerous projects that have not attracted enough attention (or without appropriate connections) may not go ahead. This lack of explicit gas investment policy creates uncertainties for companies and slows the development of natural gas projects. It represents an extra risk for companies considering natural gas projects that already require huge investment and contain high risks. There is thus a pressing need for the government to redefine its role in the gas market, and to develop a coherent framework policy on gas sector investment, which could be part of the country's comprehensive natural gas policy.

Third, China needs to enlarge the scope for foreign investment in the downstream gas market and improve investment conditions in that sector, which is a major bottleneck of large gas infrastructure projects. For example, the restriction that the Chinese side must be the majority shareholder in any gas distribution business could be lifted, as this limits the inflow of capital, for which the Chinese distributors may not have enough funding ability.

Fourth, the government needs to reform its current project approval process and refocus its attention on real regulatory issues rather than commercial aspects (e.g. the level of capital investment). It should provide a clear set of criteria for project approval and improve the transparency of the process. Through an appropriate investment framework, it should provide equal opportunities and a level-playing field for all market participants, with particular attention to small and medium-sized foreign companies, which also have important expertise to bring. Pricing reform, as discussed in Chapter 6, should also be carried out to allow more predictable revenues for foreign companies wishing to invest in China's gas sector.

All these requirements point to the need to have a sound legal and regulatory structure in place. Defining a clear and transparent specific framework for gas activities, establishing the role and responsibilities of each player, whether it be a domestic or foreign, private or state-owned enterprise, is of utmost importance for investors. Related issues will be discussed in Chapter 11.

Based on the above analysis, the following recommendations are made:

RECOMMENDATIONS ON FOREIGN INVESTMENT POLICIES AND REGULATIONS

The Chinese government should:

- Respect the commercial principles that underline any investment decision by foreign companies. These principles include long-term legal and fiscal stability, freedom in commercial decision-making, administrative neutrality, absence of political intervention, regulatory transparency, and respect of contract sanctity.
- In line with its commitments to the WTO, further improve general conditions for foreign investment in China and those in its gas sector in particular, by increasing the transparency of the regulatory and approval process.
- Move beyond the current "project-by-project" approach by developing a coherent policy framework for investment in gas infrastructure projects as part of the national gas policy.
- Carry out gas pricing reform to create an efficient gas market and to allow more predictable revenues for all market participants.
- Open further the gas distribution sector to foreign investment and improve conditions for investment in that sector.

POLICY-MAKING, STRUCTURE AND REGULATION

Highlights:

- *The new Chinese emphasis on natural gas development requires an enabling structure and an appropriate legal and regulatory framework for the gas industry. A clear government pronouncement on China's natural gas policy would be helpful, and a legal framework for mid- and downstream activities is also needed.*
- *At the nascent stage of gas market development, establishing a regulatory structure that encourages competition in infrastructure building is more important than creating competition in the use of such infrastructure. However, long-term issues related to the future introduction of competition in the gas industry should be taken into account from the start.*
- *A very important task is to remove policy-making and regulatory responsibilities from state-owned companies. This and the increased complexity of the energy system call for strengthened government capacity in policy-making and regulation. One way of achieving this is to create a new energy department within the central administration.*
- *A main factor in accelerating the development of a gas market is to establish as soon as possible minimum standards of health, safety and environment, and other technical standards for all parts of the gas industry, inclusive of gas appliances.*

In order to ensure the efficient and rapid development of the natural gas industry and to attract sufficient investment, the Chinese government needs to consider how to modernise its policy, legal and regulatory framework to create more favourable conditions for growth. The current gas industry structure and legal framework are described in Chapter 2. This chapter discusses the issues on policy-making, further restructuring of the gas sector, and gas industry regulation.

CURRENT ALLOCATION OF POLICY-MAKING AND REGULATORY RESPONSIBILITIES

At present, responsibilities for devising natural gas policies and for regulating the industry are shared by a number of different government bodies, as well as by the oil and gas companies themselves. The current allocation of policy-making and regulatory functions is as follows:

SDPC

Since the abolition of the Ministry of Energy in 1992, there has been no specific government agency in charge of energy. When the Ministry of Energy was abolished, its policy functions were transferred to the then State Planning Commission. During the 1998 reform of central government administrations, the State Planning Commission was renamed State Development Planning Commission (SDPC) to take into account the diminishing role of state planning and to promote the rapid development of a market economy. Today, the SDPC is the major economic policy institution responsible, among others, for:

- devising policies and goals for national economic and social development through the Five-Year Plans and other medium and long-term plans;
- co-ordinating major development programmes in the plans, such as the infrastructure construction programme and enterprise technology upgrades;
- formulating pricing policies and regulating the prices of major state-controlled commodities;
- setting the total size of fixed-asset investment, distributing key development projects, specifying their funding allocations and guiding the use of foreign loans;
- balancing total demand and supply, imports and exports of key products;
- co-ordinating regional development; and
- devising strategies, goals and policies to optimise the use of foreign capital to balance international payments and manage foreign debt.

In the energy sector, the SDPC formulates mid-term and long-term energy plans, approves energy projects of more than US$30 million (or RMB30 million depending whether it involves a foreign investment or a purely domestic investment), and sets prices.

SETC

The State Economic and Trade Commission (SETC) was established in 1993. It absorbed six ministries including coal, power, chemical industry, metallurgical industry, machine building industry and internal trade. It is at the same administrative level as the SDPC and is responsible for formulating and enforcing industry policies and regulations and for the administration of state-owned enterprises. As a macro-economic regulatory agency, the SETC also regulates the short-term operations of the national economy. It formulates and oversees the implementation of sectoral programmes, regulations, and annual plans for industry, transportation, commerce and trade; provides co-ordinated solutions to major economic problems; fosters the development of markets; and helps balance domestic and international trade. The SETC is often labelled the “operator” of the economy while the SDPC is regarded as the “planner”.

After the 1998 reform, the SDPC’s predominant role in energy was shared by the SETC. The 1998 reform abolished the last two energy ministries (Ministry of Power and Ministry of Coal) and assigned their functions to the Department of Electrical Power and the State Administration of the Coal Industry (SACI), both under the SETC. The reform also theoretically removed government functions from CNPC, SINOPEC and CNOOC and transferred them to the State Administration for Petroleum and Chemical Industries (SAPCI), also under the SETC. Both SACI and SAPCI were set up as temporary agencies. In October 2000, they were both abolished and their functions were transferred to various departments of the SETC. As a result, the SETC now holds the regulatory functions of all three oil and gas companies.

MLNR

The Ministry of Land and Natural Resources (MLNR) was established in 1998. It regrouped the relevant government functions related to land and natural resources that were separately assumed by various organisations: the State Land Administration, the Ministry of Geology and Mineral Industry, the State Ocean Administration, the National Mineral Resources Committee, the State Planning Commission, the ministries of coal, chemicals and metallurgical industries, the China Nuclear Industry Corporation and the China Non-Ferrous Metal Industrial Corporation.

Acting as the upstream regulatory agency, the main functions of the MLNR in relation to oil and gas resources include:

- formulate and promulgate laws, decrees, regulations and policies, as well as technical standards and procedures;
- prepare and implement plans for mineral resources administration;
- supervise authorities of different levels on land and resources administration, investigate and prosecute major unlawful cases;
- handle mining rights applications, issue E&P licenses, review and approve license transfer and confirm results of mining rights evaluation;
- review and approve concessions open for foreign investment;
- evaluate mineral reserves and manage geological data;
- levy mineral resources compensation tax and manage its utilisation.

Other ministries

The Ministry of Construction, the Ministry of Labour and Social Security and the Ministry of Public Security also have regulatory roles in the gas sector, namely with regard to urban gas network construction and operation. The Ministry of Construction is responsible for the issuance of operation and construction permits to urban gas developers. The Ministry of Labour and Social Security is responsible for overseeing urban gas supply safety, while the Ministry of Public Security is responsible for the supervision of fire control for urban gas supply systems.

Local authorities

In 1998, most provincial-level companies involved in the oil or gas business were integrated either into CNPC or SINOPEC. However, provincial governments retained substantial power over China's energy policy. As many provincial party secretaries are members of the Central Committee, they protect provincial interests during the policy-making process. And due to China's physical size, the central government must delegate some authority to each provincial government, whose hierarchy level is equal to that of central government ministries, and whose resources and personnel are often much more adequate. Also, the move towards a market orientation of the gas industry helps local governments to gain more power over local resources.

In most cases, local authorities own the companies that distribute both natural gas and coal-based manufactured gas.

CLARIFYING THE LEGAL FRAMEWORK

There is a clear and urgent need to clarify the legal framework governing the natural gas industry in China. At present, structural and regulatory issues concerning natural gas – including pricing, project authorisation and equity participation – are addressed *ad hoc*, with little consistency across the country. Policy is effectively being developed on a project-by-project basis. This has led to regional disparities in regulations, creating a mood of uncertainty and heightening perceptions of risk among potential investors. The establishment of solid legal foundations and a consistent approach to regulation of the sector, based on best practices in other countries, would contribute significantly to alleviating these problems and encouraging investment.

The case for a natural gas law for the downstream industry

Almost every country where a natural gas industry has been established, whether based on indigenous resources or imports, has adopted a gas law or laws in the early stages of market development. In most cases, these laws cover mid- and downstream aspects of the industry. Upstream aspects (where relevant) are usually covered by separate legislation covering both oil and gas. These laws are often amended as the industry matures or in response to changing market circumstances and policy objectives. Laws in North America and all countries of the European Union have been modified in recent years to introduce gas-to-gas competition based on third-party access to the network.

At the national level, there is no specific Chinese law dealing with the natural gas industry. This is not only because gas has always been considered a part of the oil industry and, until recently, gas transportation and consumption have been on a relatively small scale, but most importantly, there has been no specific law on oil. With the growing interest in new gas supply projects in China, there is a strong case for introducing as soon as possible a law covering the mid- and downstream natural gas business to deal with the specific characteristics of the industry and to ensure a harmonised approach to gas industry development.

Adopting a specific law for the mid- and downstream natural gas industry that establishes the fundamental rights, obligations and regulatory principles would provide a clear legal expression of the government's policy and strategy for gas industry development and the ground rules for the operation of the gas industry. Such a law would, therefore, help create a more stable investment and operating environment, reduce uncertainty and investment risk, and consequently lower the cost of capital. Indeed, industrial players would like to use take-or-pay contracts for long-term gas supply, but the lack of a specific legal basis has rendered contract negotiations difficult. Codifying the roles and responsibilities of different players in the industry would reduce conflicts of interest and ensure a level playing field for all. Aspects of the industry that a gas law would need to address include the following:

- Broad objectives for the development of the gas industry;
- Rights, responsibilities and obligations of the various government agencies and companies involved in gas transmission, distribution and marketing;

- General principles for licensing, including administrative procedures and criteria to be used by the relevant authorities for issuing licences, authorisations and concessions. Licensing and approval procedures and criteria need to be transparent and straightforward to streamline decision-making on new projects;
- Specific rules on licensing, authorisations and concessions for high-pressure transmission, storage, LNG and piped gas importation, regasification and storage, low-pressure local distribution and marketing. The precise terms and conditions of those licences, authorisations and concessions may be laid down in the primary legislation or in secondary legal instruments, such as ministerial decrees. Procedures would also cover approval of long-term contracts for the purchase and sale of gas[1];
- Allocation of functional responsibilities to public organisations for licensing and regulation of the various activities of the gas companies at each stage of the supply chain;
- Tariff principles to be applied by the responsible authorities, in accordance with the national "Pricing Law";
- Use of land, rights-of-way, health and safety and environmental rules and procedures;
- Technical issues, such as standardisation of operating practices;
- Contractual issues, including the enforcement of long-term take-or-pay contracts;
- Procedures for dealing with disputes;

In elaborating the gas law, particular attention should be paid to the flexibility needed to cope with the evolving nature of the gas industry to avoid the types of problems faced by the 1996 "Electricity Law"[2].

Revision of upstream legislation for oil and gas

In addition to a natural gas law that covers mid- and downstream gas activities, a national law covering upstream oil and gas resource management is also needed. The 1986 Mineral Resources Law and the two sets of regulations for onshore and offshore JV oil and gas explorations are the central elements of the legal framework for oil and gas exploration and production. Rules specific to oil and gas are dealt with mainly by regulations issued by the Ministry of Land and Natural Resources and administration systems set up by the Ministry and provincial and municipal governments. This legal structure has problems, including a lack of coherence and harmonisation in rules governing upstream operations and ambiguity with respect to the rights and responsibilities of domestic and foreign companies and the administrative functions of the central and provincial governments. Also, many of the regulations are inconsistent with the more market-based approach now being taken to develop the energy sector.

The adoption of a comprehensive modern law, covering the management of upstream oil and gas resources and the fiscal regime, would clarify the legal and administrative framework,

1 Approval means that the regulatory authority is not involved in the negotiation of contractual terms and conditions, but it has the right to object before the contract takes effect if it judges that any aspect of the contract may work against the public interest.

2 The "Electricity Law" was passed in 1995 at the time of severe supply shortage and, although it helped resolve issues at the time, lower efficiency and bad services have resulted in the long term. This law quickly became unable to provide a legal basis for emerging issues such as separation of generation from transmission and competition among generators. There is an increased call in China for a revision of the law.

strengthen investment guarantees and reduce the scope for corruption. Properly designed, it could also, as in many countries, be used as a marketing tool to attract foreign investment. The law would need to address *inter alia* the following issues:

- rights and duties of all industry participants (private and state companies) and government agencies;
- limits on the degree of discretion to be used by government agencies in decisions on upstream matters, including licensing;
- procedures and criteria for awarding rights and licences;
- fiscal arrangements and procedures for modifying rights and licenses over time;
- licence conditions, including duration and conditions for relinquishment;
- access to land, health and safety and environmental considerations; and
- dispute settlement and arbitration.

The process of elaborating new legislation or modifying existing laws should involve consultations with industry stakeholders, as well as careful, detailed analysis of and reflection on key issues. Setting out such a new legislation is likely to take some time. As suggested in Chapter 3, the government should, in the meantime, make a clear and formal statement of its policy on natural gas, including clear signals of how it intends to regulate different aspects of the industry.

ORGANISATIONAL AND INSTITUTIONAL ARRANGEMENTS

The main problem with regulation is that the state-owned oil and gas companies continue to exercise the policy-making and regulatory functions of the government. A key priority of regulatory reform must therefore be the effective and complete removal of regulatory and policy-making functions from these companies to allow them to focus on business activities and to ensure a level playing field between state and non-state companies.

Reorganising policy-making, ownership and regulatory responsibilities

While government administrations are taking over policy-making and regulatory functions from state-owned companies, the Chinese government needs to decide how best to reorganise the functional activities of the various state agencies, as the gas industry develops and new players enter the market.

Generally speaking, government responsibilities in the gas sector are focused on the following three areas:

- *Policy formulation* involves the identification of priorities and strategies for gas sector development and the establishment of a coherent framework of laws, regulations and other instruments to allow effective regulation of the market.

- *Ownership* of state-owned gas companies entails responsibility for setting strategic objectives for those companies and deciding how they are to be managed.

- *Regulation.* In its broadest sense, this involves the implementation of policy, involving both routine technical functions, such as licensing, as well as general monitoring and economic regulation to deal with company behaviour that may go against the public interest, including pricing and access.

There is no catch-all, prescriptive approach to the functional organisation of governmental activities in the natural gas sector. But governments need to take account of the key principles that form the basis of effective governance of all network industries, including the gas industry, based on experience in OECD countries (Box 11.1).

Box 11.1

Characteristics of Best Practice Regulation of Energy Networks in OECD Countries

Regulatory frameworks and institutions vary considerably between OECD countries, reflecting differences in legal and political traditions, industry structure and approaches to regulatory reform. In particular, differences exist in the division of jurisdictional powers between government, the courts, the general competition authorities, the national regulatory authorities and, in federal countries (such as the United States, Germany and Australia), the state regulators. There has been a trend in recent years towards the creation of regulatory agencies, although their sectoral scope, responsibilities, powers and degree of independence from government also differ greatly from country to country.

Regardless of the specific design of the institutional framework, the features of regulatory arrangements that are generally regarded as being desirable in OECD countries include the following:

- Open and transparent processes that are credible to all parties.
- Decision-making that is informed, reflective of best practices and objective. This implies adequate resourcing of regulatory bodies and a separation of regulatory functions from the operational aspects of the industry.
- Appropriate separation of administrative and decision-making powers.
- An appeals process that ensures that decisions conform with mandated objectives.
- Low administration, enforcement and compliance costs.

If regulators are to succeed, they must establish credibility with investors and legitimacy with consumers and other stakeholders, and they must produce results that enhance efficiency for the economy as a whole. A failure to do so can undermine investor confidence, leading to a higher cost of capital and lower investment.

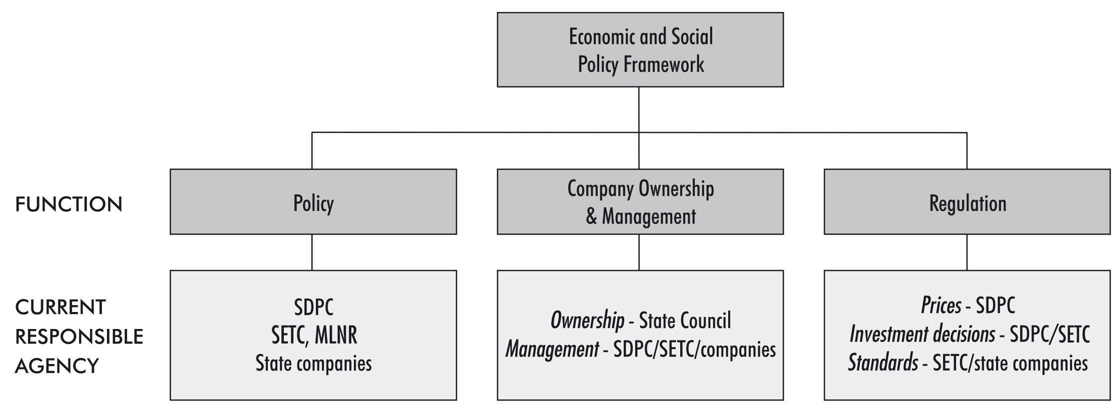
Experience around the world has demonstrated the merits of clarifying and separating responsibilities for policy-making, ownership and management of state companies, and regulation. The separation of each set of responsibilities is needed to:

- prevent collusion between government agencies and state companies and, therefore, discrimination between state and non-state companies;
- reduce the potential for conflicts of interest within government departments that carry out more than one of these roles;
- improve the transparency of government and reduce the arbitrariness of decision-making, thereby reducing uncertainty, increasing predictability, lowering the cost of capital and increasing the attractiveness of investment;
- concentrate expertise and competence in each area, which would lead to more efficient governance.

The Chinese government has already taken positive steps in this direction by transferring certain technical regulatory functions from the SDPC to the SETC. Figure 11.1 shows the key elements of each functional activity and the current allocation of energy policy and regulation responsibilities.

Figure 11.1

Current Allocation of Gas Industry Functional Responsibilities



Source: IEA analysis.

But there is a need for further segregation and clarification. At present, these functions are spread across several government agencies and the state companies, with little co-ordination of policy and regulatory activities. Several agencies are involved in each of the three responsibility areas. There are also gaps in the current structure, including a lack of coherent mechanisms for approving and licensing new transportation and LNG import projects, and for overseeing harmful upstream practices, such as flaring. Moreover, there is a lack of transparency and accountability in regulation.

The need for a specialist energy department

Since the abolition of the Ministry of Energy in 1992, there has been no single central-government entity in charge of energy policy and regulatory matters. Energy policy and regulatory responsibilities were initially transferred to the SDPC after 1992, and the 1998 government reform centralised the upstream responsibilities in the Ministry of Land and Natural Resources, but the mid- and downstream activities are still supervised by several administrations, in particular the SETC and SDPC.

Theoretically, the SETC is the body responsible for energy matters as it centralises the responsibilities of power, coal, and oil and gas. But in the SETC, only the Department of Electrical Power is a specialised energy department, responsible for regulating the operations of the power industry, while those of the coal industry and the oil and gas industry are regulated by several other departments, in particular the Department of Economic Operations.

In reality, however, the SDPC's role in energy matters is much more important than that of the SETC as it approves investment projects, decides energy prices and exercises supervisory power on energy companies and industry. In the SDPC, the energy and transportation department was abolished in 1998 and today energy responsibility is shared mainly between the Department of Basic Industries and the Department of Industrial Development. In addition, the Department of Pricing sets the prices of energy products along with other key commodities. The SDPC houses the Office for the West-East Gas Pipeline. One Vice-Chairman of the SDPC is considered the *de facto* Minister in charge of energy, but his scope also includes other important industries, such as information technology and biotechnology.

The situation is rather confusing as to who is really in charge of energy matters, and clarification on the respective roles of the SDPC and SETC in the energy sector is needed. The abolition of the State Administration for Petroleum and Chemical Industries (SAPCI) in October 2000 was a positive move. Until then, state oil and gas companies were supervised by three government agencies. However, the supervisory functions of SDPC and SETC, and the *de facto* policy-setting role partially exercised by the state oil companies made the semi-independent SAPCI redundant, which explained its uneasiness in dealing with the state oil companies during its short existence. To further complicate matters, as both the SDPC and SETC are comprehensive economic agencies, they do not always have the necessary in-depth technical knowledge on complex issues related to the operation of the energy industry, in particular, the two network industries of electricity and natural gas. As a result, they often call on energy companies to provide technical expertise. The partiality of this assistance may, of course, be questioned. Although the SETC initially drew many of its staff from energy companies and absorbed a large number of employees from the abolished SAPCI, those people and thus, their knowledge, have been dispersed among different departments. With the exception of the Department of Electrical Power, there is no centralised expertise in the SETC to deal with energy matters. In total, there are just a few dozen energy specialists within SDPC and SETC, whereas in many other, far smaller, countries, a single electricity regulatory agency often has a staff of several hundred people.

So there is a strong case for establishing a specialist energy department within the central government administration in China, to cover oil, gas, electricity, coal and other energy sources. The following factors make the case even stronger:

- China's oil dependency is growing, and there is a pressing need for a co-ordinated approach towards energy security;

- competition in the electricity, oil and gas industries is just beginning, and in the future there will be more and more complex market-related issues that need specialised expertise within the government to resolve;
- China's WTO membership will further open its energy sector and bring new international issues on energy trade and investment;
- concentration of energy knowledge and expertise in a single body would facilitate macro-economic planning and accelerate problem resolution;
- there is a need for increased coherence and co-ordination in energy policy-making; and
- better communication of energy policy decisions to industry stakeholders is also critical.

To be effective, such a department should be appropriately resourced in order to build strong information and analytical capabilities.

One important question is where to place the new specialist energy department. There are basically three options: under the SDPC, under the SETC, or totally independent from both and reporting directly to the State Council. The first two options require a regrouping of energy sector responsibilities from the two existing commissions. This can only work if suitable ways can be found to avoid the SAPCI problems as described earlier, that is, unclear definition of responsibility, redundancy with authority of the mother institution, and having several administrations on top of energy companies. The third option has some merits, but its responsibility and authority need to be clearly defined *vis-à-vis* the two existing commissions to avoid having three central government agencies each having duplicative or unclear roles.

Separation of responsibilities for policy-making and regulation

In most OECD countries, policy-making and regulatory functions are assigned to different government agencies. Initially, however, it may be appropriate in China to give full responsibility for regulation and policy-making to the new energy department as suggested above, given the limited experience and skills in gas policy and regulatory issues that currently exist in China.

At a later stage, the government will need to consider the merits of establishing a separate national regulatory agency, with responsibility for day-to-day regulation of the gas industry, especially if the national authorities continue to regulate wholesale gas prices. International experience demonstrates that separate regulatory agencies, often enjoying a degree of independence in day-to-day decision-making from the government or ministry, can regulate network industries in an efficient and non-discriminatory way. This is especially important when introducing gas-to-gas competition based on mandatory third-party access to the network in the future.

In a growing number of countries, responsibility for regulating the gas and electricity industries is combined in a single body to keep pace with the trend of convergence between both industries – gas-fired power plays a growing role in a new gas market. The Chinese authorities will need to decide whether the pace of development of competition in both gas and electricity markets warrants the creation of a single agency covering both sectors, or two separate agencies. In the long run, a single agency will probably be the best solution.

Management of state-owned companies

Another key aspect of reform is the government's relationship with the state companies, when the latter are no longer involved in policy-making and regulation. For as long as the state retains control over the gas companies, it will need to set those companies' strategic, operational and financial objectives. It has been argued above that the key priority should be the effective and complete removal of government functions from energy companies. Although the government has made some progress in putting those companies onto a more commercial footing through corporatisation and public listings of shares, there continues to be widespread *ad hoc* intervention in the management of those companies by political leaders in support of particular projects without consideration being given to their commercial merit.

It would be more efficient to devolve full responsibility for day-to-day management to the companies themselves, governed by a board of directors and a government-appointed Chief Executive, and establish a more arms-length relationship between the government and the companies. One way in which this can be achieved is by negotiating planning agreements or contracts with the wholly state-owned holding companies, setting out specific objectives and performance targets, covering a period of several years. This approach has proved successful in several countries, for example in France, where the state is the single owner of the national gas and electricity utilities. Responsibility for managing the state's holdings in gas companies must be given to a separate body from the one that is responsible for policy and regulatory matters to prevent discrimination in favour of those companies.

GAS INDUSTRY STRUCTURAL REFORM

The primary objective of structural reform should be the removal of structural impediments to gas market development. Such impediments include:

- The *de facto* geographical monopoly in the upstream sector, where CNPC (including mainly PetroChina), SINOPEC, and CNOOC are the unique producer in their respective areas following the 1998 partition (although through the acquisition of CNSPC, SINOPEC now has a limited interest in both CNPC and CNOOC's areas). This has limited the growth of competition in gas production.
- The lack of competition in the building of gas pipelines, as it is usually the gas producers of the respective geographical areas that build the pipeline to transport their gas.
- As a result of the above two factors, there is an automatic upstream integration with the midstream transmission business, which may not be conducive to new market entrants in both the upstream and midstream sectors.

Box 11.2

Government Involvement in the Natural Gas Industry

In most European countries, including Belgium, France, Italy, the Netherlands, Spain and the United Kingdom, the central government was heavily involved in the initial development of the natural gas industry through the creation of state-owned companies. In most cases, the state-owned gas companies were subsequently privatised and their exclusive rights removed as part of the liberalisation process.

Today, the degree of vertical integration in each country reflects the historical evolution of the industry. In most continental European countries and North America, high-pressure transmission is carried out by companies that are separate from production and processing activities and local distribution. In the United Kingdom, transmission and local distribution is carried out almost entirely by a single company, Transco, although it no longer has exclusive rights to develop the network. There are a few examples of integrated gas production and transmission companies, notably in Germany (such as BEB and Wintershall). The degree of horizontal integration also varies markedly. In Belgium, Italy and the Netherlands, a single company dominates transmission, while in the United States and Germany a number of separate pipeline companies serve different regions with a limited degree of overlap.

In OECD countries, governments to a varying degree have been involved in the early structural design of the gas industry (Box 11.2). Theoretical options do exist for China to redesign its gas industry to remove the structural impediments listed above. But in practice, any further structural re-design will have to take into account the following constraints:

- The dust from the major oil and gas industry restructuring in 1998 has just settled. Consequently, unless there is a serious problem in the current structure, it is undesirable to undertake any further industry restructuring.
- Furthermore, all three domestic oil and gas companies have been partially privatised and listed in international stock exchanges. So there is a need to maintain stability and preserve the interests of existing investors.

Under these constraints, subdividing PetroChina, Sinopec and CNOOC into multiple production companies, or any heavy-handed, highly interventionist approach such as mandatory divestment of assets by existing players, is unlikely to be practical. Similarly, the separation of gas production and processing activities from PetroChina's oil production activities is unlikely to be viable on technical and economic grounds. Some 30% of gas production in China is associated with oil and, therefore, cannot be separated. In addition, there are important economies of scale in combining oil and gas production activities. Most upstream companies around the world are involved in the production of both oil and gas, although there are virtually pure gas production companies in the United States and Russia (Gazprom).

Achieving a more diversified and competitive upstream industry

The best approach would most likely be to encourage new entrants, including international oil and gas companies and other private investors, in each link of the gas chain. This could start with the opening of the upstream sector and improving the attractiveness of the investment environment to new entrants. A more diversified upstream sector would firm up gas reserve estimates, boost production and lower the development and production costs of domestic gas.

To achieve this, the government should reinforce efforts to introduce competition and encourage investment by experienced international oil and gas companies in exploration and production. Improving access for these companies to upstream oil and gas mineral rights and to markets is critical, as suggested by a recent World Bank report[3]. In addition to those actions suggested by the World Bank, the government could also envisage the following measures to increase upstream diversification:

- Reallocation of exploration and development rights currently held by the state-owned companies to new entrants.
- Establishment of a market for mineral rights, or other measures that would accelerate the exchange of mineral rights.
- Discretionary licensing of areas not already leased.
- Further joint venture partnerships.

The AEPC Natural Gas Initiative, endorsed by the APEC Energy Ministers in October 1998 also includes a number of general recommendations to promote the development of natural gas exploration and production in the APEC region[4].

Attention to problems of vertical integration

At present, there is a large degree of vertical integration in the Chinese gas industry, namely between production and transportation activities. The vertically integrated structure has some advantages, as gas producers can market their gas directly with minimum transaction costs. It also reinforces the investment synchronisation along the gas chain and reduces the risks associated with the weakness of contractual enforceability. In the early stage of gas market development, this relatively simple structure is perhaps the most suitable.

However, there is a need to pay close attention to possible problems that a vertically-integrated gas industrial structure could pose over the long-term, when the gas infrastructure is more developed. In a vertically-integrated industry, when the owner of the gas pipeline also competes in gas production and distribution, it typically has both the ability and the economic incentive

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3 The World Bank report suggested the following key actions to improve access to upstream oil and gas mineral rights:
- Review fiscal terms to assess international competitiveness;
- Increase the number of exploration areas for the bidding and award of production-sharing contracts (PSCs) and offer more prospective exploration rights;
- Make all new and relinquished exploration blocks eligible for PSCs through annual competitive rounds managed by an independent agency that has the authority to sign the PSC.

Source: Modernising China's Oil and Gas Sector: Structure Reform and Regulation, joint report by the World Bank and the Institute of Economic System and Management of the State Council's Office for Reform of Economic System (IESM/SCORES), March 2001.

4 "Recommendations concerning accelerating investment in natural gas supplies, infrastructure and trading networks in the AEPC region", an Initiative endorsed by the APEC Energy Ministers at their third meeting in Okinawa, Japan, 9 October 1998.

to restrict competition in both activities. It has the ability to restrict competition by denying or restricting access to the pipeline by other gas producers, or by raising the price, or lowering the quality and timeliness of the services relative to those it provides to its own upstream and downstream affiliates. It has the economic incentive to re-capture some of the monopoly rents in downstream by restricting competition from other companies, or by discriminating against non-affiliate companies. The diversification of upstream activities, as advocated above, can realistically work only when all producers can have non-discriminatory access to pipeline transmission to sell their gas. For example, SINOPEC, which is currently allowed to produce gas in areas dominated by CNPC, can sell its gas *via* the latter's pipelines, and *vice-versa*. In any case, China would want to avoid a recurrence of what happened in its electricity sector, where the State Power Corporation's (or its subsidiaries') ownership of both transmission and generation assets impeded the development of effective competition from independent generators.

The key issue is therefore to remove both the ability and incentive of the owner of the monopoly segment (pipeline) to restrict competition in competitive segments (gas production and gas sales). Vertical separation is one way of solving this problem from its structural roots. The structural separation of upstream (production and processing), midstream (national and regional transmission and storage) and downstream (local distribution) allows competition between producers in selling to pipeline transmission companies and the latter in selling to distribution companies. It ensures that each company focuses on its core activity. It allows for costs to be better allocated to specific functions, limiting the scope for cross-subsidisation. Vertical separation also simplifies tariff regulation, where this is needed, as activities in upstream, midstream and downstream are very different from one another[5].

Vertical separation may, however, entail some costs. In particular, it may increase the transaction cost between various segments of the supply chain. It may also lead to inefficient investment decisions[6]. For a nascent gas market like China, vertical separation may not be the appropriate approach.

There are a number of alternatives to full vertical separation of ownership:

- One way is to have a joint ownership of the transmission company by all firms that are engaged in competitive activities upstream and downstream. Since all competing firms are part-owners of the pipeline facility, they can ensure that they have non-discriminatory access.
- A second approach is accounting separation, that is, a requirement on the integrated company to prepare separate accounts for its upstream, midstream and downstream

5 The core skills involved in building and operating a pipeline network differ significantly from the competencies required for exploration and production. In most OECD countries, specialist companies not directly involved in oil and gas production generally carry out gas transmission, although producing companies often hold shares in gas transmission companies. Those transmission companies are increasingly developing their activities on an international scale (horizontal integration). In China, the transmission business is small at present and PetroChina's experience in operating onshore high-pressure lines is limited. It is not advisable at this stage to break up PetroChina's transmission business into separate pipeline companies. However, there would be benefits for PetroChina or any other company to set up a transmission subsidiary specialised in pipeline building, operation, maintenance and storage.

6 The reason is that in fast growing gas markets (even in Western Europe), the contracting of large volumes of gas from producers goes hand-in-hand with the design and construction of the transport system needed to bring the new volumes to the market. *Source: Regulatory Reform: European Gas,* IEA, 2000.

activities. This includes the company charging itself the same prices for transport services as it does others, and stating separate prices for the commodity, transport and ancillary services.
- A third approach is management or functional separation, requiring the gas company's activities to be carried out with separate, distinct divisions or subsidiaries of the vertically integrated company.

At present, the only upstream company with any involvement in local distribution is PetroChina, which has a stake in the Beijing Natural Gas Company. But any increased involvement of upstream/midstream companies in local distribution could impede the development of competition between upstream companies in marketing to local distributors. In a developed gas market, transmission companies and the companies with controlling stakes in them should not normally be allowed to hold majority stakes in the distribution companies they serve, to prevent them from abusing their market power. This type of restriction, which has been used in the gas and electricity sectors in several countries, such as Argentina and the United Kingdom, has been shown to be effective in ensuring a level playing field in marketing gas (and electricity) to local distribution companies. However, producers in nascent gas markets usually want to have an ownership interest in transmission and distribution, either because there are no other investors or because they want to control directly the pace of downstream market development. In this event, cross-ownership may be permitted, either indefinitely or for a fixed period, while gas markets are developing. The Chinese authorities will need to carefully monitor the need for restrictions on cross-ownership.

REGULATION OF GAS TRANSMISSION AND DISTRIBUTION

Regulation in the widest sense of the term involves intervention by public authorities (central, regional or local) in the market, in order to influence or control the behaviour of market participants and market outcomes, in particular to ensure a competitive environment and a level playing field. The government sets the rules by legislative or regulatory means to determine which firms can or must engage in particular activities. The regulatory agencies implement the rules and control their application[7]. They seek to prevent companies with market power from making excess profits, primarily by means of controls over tariffs and other terms and conditions of service. They can also set technical standards for the construction and operation of gas infrastructure and equipment and for health, safety and environmental control.

While there is little difference between countries on technical regulation, the approach to economic and structural regulation varies enormously across countries according to policy objectives, political traditions, and institutional and structural factors. They also differ significantly depending on the maturity of the gas market. The regulatory framework that is currently in use in North America and Western Europe is adapted to countries with a well developed gas industry and markets, and is certainly too premature for China. However, there

7 The role of a regulator can be compared to that of a football referee (or arbitrator), whose task is to ensure that the rules of the game, set by the F.I.F.A., are respected, the game is fair, and that there is no cheating. For the arbitrator to be effective, he or she must be independent of any political or other pressures, and must have the ultimate authority.

are a certain number of regulatory principles that are common to all, regardless of their market maturity. They include the rule of law, transparency, neutrality, accountability and independence.

- The rule of law is the foundation of a regulatory system as it ensures the legitimacy of regulation;
- Transparency is essential for regulatory quality. Transparency involves the capacity of regulated entities to express views on, identify, and understand their obligations under the rule of law. It is an essential part of all phases of the regulatory process – from the initial formulation of regulatory proposals to the development of draft regulations, through to implementation, enforcement and review and reform, as well as the overall management of the regulatory system. A recent OECD report noted that improving regulatory transparency is a high priority and that public consultation and accessibility are two key issues for improving transparency in China[8].
- Neutrality means that the regulations should be neutral to all market players without favouring one or another group (non-discrimination).
- Accountability: regulatory agencies, like any other public body, should be accountable for their actions and be subject to adequate efficiency control.
- The independence of regulatory agencies *vis-à-vis* the regulated companies and the government is a prerequisite for any sound regulatory system. Their independence from government and political actors is highly desirable to ensure long-term stability of regulatory policies. This independence is critical in countries where there is public ownership of gas utilities.

As discussed in Chapter 3, China's natural gas market is still at an early stage of development. The objective of a policy framework is to attract and protect private investment in order to build up the gas market, given the enormous amount of capital that will be required. Establishing the right incentives for building the needed infrastructure is perhaps more urgent than introducing competition in the use of it. Consequently, regulations, which are mainly to ensure that markets and competition work, should be kept simple and straightforward and reasonably stable over time. At this stage of development of the gas industry in China, they should focus on technical, environmental and safety standards to ensure timely construction and safe operation. They should provide incentives for efficient gas infrastructure building. Those market segments where market power could be abused also need some attention.

Establishing standards and norms for timely construction and safe operation

Technical regulations (including environmental and safety regulations) are key to a modern gas industry. They should be developed as soon as possible to ensure timely construction of the infrastructure in accordance with internationally acceptable technical standards. Standards should cover national gas specifications and metering so as to ensure system integration in the

8 "An OECD Perspective on Regulatory Reform in China", in OECD 2002, *China in the World Economy: The Domestic Policy Challenges,* Paris.

future. They should also cover standards for gas appliances and those on health, safety and the environment. A licensing procedure should be established with a clear set of rights and service obligations for all participants in the gas business. Only companies that meet those rights and obligations and respect the defined standards should be licensed.

Protecting investment

Protecting investment is particularly important at the initial stage of gas market development, as gas infrastructure facilities are very capital intensive with a very long pay-back period. Investors will be reassured by the existence of a legal and fiscal framework which is clear, transparent and stable, and that maximises the prospect of a reasonable return over the long term. Historically, gas companies setting up a grass-roots transmission and distribution business in other countries (e.g. France, UK) have often been granted monopoly rights over transportation and supply within a given area and for a given period, in exchange for the fulfilment of certain obligations. In almost no instance have they been initially required to offer pipeline access to third parties.

Exclusive rights were seen as necessary at an early stage of the development of the gas industry to reduce risks, and thereby to increase investment. New gas transportation projects are perceived by most investors as carrying substantial risk, in terms of construction costs and market off-take. Given the large initial investment and correspondingly high marginal costs in pipelines, financing typically hinges on assurances about future pipeline usage. These are normally provided by a combination of long-term contracts with large buyers, such as power plants, and guarantees of demand from customers within a given geographic area. These arrangements help reduce market risk and increase the potential profitability of investments. Exclusive rights given to a gas transportation company allow it to act as aggregator who can develop the market and balance gas supply and demand.

The gas industries of North America and Europe were developed on the basis of varying degrees of exclusive rights over high-pressure transmission and supply/distribution. The initial investments may not have occurred without minimum protection and the possibility for the gas utilities and producers to earn an adequate return on their investment. To develop a new gas market, a certain level of investment protection will be needed. This can be done *via* exclusive rights for a limited period. An example is the license awarded in 1997 to Pheonix Natural Gas in Northern Ireland to build and operate a distribution network in the Greater Belfast area (Box 11.3). The license gives Pheonix exclusive rights over gas distribution for 20 years and over supply for up to eight years. China is certainly very different from Northern Ireland, and does not necessarily need to follow this example. This simply shows a case where competition was not introduced right at the beginning of the development of a gas market.

Box 11.3

Regulation in a New Gas Market – Experience of Northern Ireland

The Northern Ireland authorities had been eager to develop a natural gas market, both for environmental reasons and to make the province more attractive to foreign investors. Their effort was triggered by the conversion to natural gas of a power plant in Northern Ireland, which was commissioned in 1996 with gas transported from Britain by a sub-sea pipeline, which provided an opportunity to develop urban gas distribution. To seize this opportunity, the authorities granted the Pheonix Natural Gas Company a license to supply gas to the greater Belfast area, which accounted for 40% of the total population in the province. The license gives Pheonix exclusive rights over transportation for 20 years, and over supply for up to eight years.

These exclusive rights are accompanied with obligations. In particular, the license requires Pheonix to complete its pipeline network in Belfast within 12 years, and to perform the work in each of Belfast's 12 districts in a specific order, within a specific timeframe. Moreover, a pipeline must run within 50 metres of 90% of the homes in each district. If Pheonix does not meet its obligations, it will lose its exclusive right in the districts where it fails so that other companies could be granted the license.

For the first five years, there was no regulation of gas prices to consumers, other than the rules barring discrimination. This is because strong competition exists between gas and alternative fuels. However, the license provides that after the initial period, the authorities can introduce a price formula if it is judged that consumers' interests are not adequately protected by competition between fuels or with the gas market.

The regulatory process was also rather simple. As both the regulator and the gas company shared the same goal of rapid gas market development, the authorities tried not to burden small and medium-sized companies with unnecessarily high costs of funding the regulator's office, staffing a big regulatory affairs team, or funding inquiries from the Monopolies and Mergers Commission.

Source: Peter Lehmann, 1999. *Regulation in New Natural Gas Markets – The Northern Ireland Experience. Viewpoint,* World Bank.

Third-party access?

It is only when a gas market has been significantly developed and reached a high degree of maturity that such regimes as the "third-party access" (TPA) could be introduced to increase competition and efficiency. As described in Box 11.4, the application of such a regime requires certain conditions, the most important of which is the existence of excess capacity in both supply and transportation. As those conditions do not yet exist in an emerging market such as China, it is premature to introduce a TPA regime today. Indeed, the 1998 European Union gas directive, which took effect in 2000, also includes derogations for emerging markets, such as Greece and Portugal, which can delay the introduction of competition through third-party access. This will protect the investment realised by the incumbent gas utilities.

Box 11.4

Third-Party Access

Third Party Access (TPA) is the right of a third party (either a producer, a consumer, a shipper or a trader) to access/make use of the transportation and related services of a pipeline company for a charge (tariff) to move gas owned by the third party. In 1992, the European Commission defined it as "a regime providing for an obligation, to the extent that there is capacity available, on companies operating transmission and distribution networks to offer terms for the use of their grid, in particular to individual consumers or to distribution companies, in return for payment". It evokes a right for any third party to buy the transportation service of a pipeline company and an obligation for the latter to offer such services, although the extent of such right and obligation may be limited by relevant legislation. It therefore differs significantly from voluntary access, which can take place freely without public intervention. TPA may also apply to LNG terminals and other infrastructure.

In practice, essentially two kinds of TPA exist: a regulated regime and a negotiated one. In a regulated TPA, the public authorities set the rules and access conditions, on the basis of published tariffs and/or other terms and obligations for the use of the system. Negotiated TPA requires the pipeline company to publish its basic conditions for access and related services, but leaves the parties concerned the freedom to define access terms and conditions.

Regardless of whether TPA is regulated or negotiated, there are certain conditions for the application of such a regime:

- There should be a sufficiently well developed gas market with excess pipeline transmission capacity;
- There should be a sufficiently large number of gas producers and consumers who seek to have access to the spare capacity rather than building their own pipelines; and
- Physical links exist or are feasible with the existing pipelines.

In addition, to ensure access to all network users (or a defined class of customers, known as "eligible" customers), be they customers or companies, on equal conditions, impartiality and neutrality, a number of other issues have to be considered before the introduction of TPA in a country. They include:

- Eligibility for participation: it has to be decided which category of companies should be able to benefit from TPA and, for instance, whether they should be of a certain minimum size (if gas consumers) or have to meet technical and financial standards (if shippers).

- Definition of facilities to which access is to be granted: e.g. transmission and distribution pipelines both onshore and offshore; LNG facilities; gathering, storage, treatment and blending facilities.
- Definition of the services that may be involved apart from the transmission: e.g. metering, pressure balancing, quality management, load balancing, storage, back-up and stand-by services.
- Determination of the extent to which the pipeline company is obliged to provide these services separately; i.e. to what degree these services should be unbundled, which also raises the question of whether the pipeline company has to split its activities into separate companies.
- Definition of available capacity and the procedures to be followed when capacity is not sufficient (queuing procedures, requirements to build capacity).
- How to calculate the tariffs for transportation and related services.
- How much information the pipeline company will be required to disclose regarding availability of, and calculation of charges for, services.
- The relationship (degree of discrimination) between the pipeline company's own customers and third parties requesting access.
- The regulatory framework (regulatory bodies involved, instances of appeal, etc.)
- Legislation dealing with transitional problems caused by the introduction of TPA.
- Dispute settlement mechanisms to ensure expeditious resolution.
- Mechanisms to avoid abuse of dominant positions.
- The obligation to unbundle accounts.
- Technical rules to ensure inter-operability between gases of different quality.

Source: IEA.

In view of international experience and the need to provide strong incentives to investors, it is appropriate for the Chinese government to offer a degree of protection to investors in high-pressure transmission pipeline and LNG projects and local distribution networks. In the near term, no transmission, LNG or distribution company should be legally obliged to offer transportation or regasification services to third parties (at least for a given period), although the companies would be free to negotiate such a service if they so wish. In practice, this would mean that each producer would in most cases have no choice over which transmission company to sell its gas to, unless there happened to be more than one transmission line within the vicinity. Similarly, there would be a single buyer of gas for local distribution for each supply area, although there could eventually be more than one transmission company supplying a single distribution area with gas from different fields and basins. The introduction of a third-party access regime to encourage gas-to-gas competition should nonetheless remain a longer-term objective, and the government should make its intention and timetable for introducing TPA clear to investors.

Exclusivity in gas transmission pipelines?

One critical issue on gas pipeline regulation is its exclusivity, which could apply to 1) a geographical area (either producing area or consuming area), 2) a route that links a producing basin to a city, or 3) the physical asset of the pipeline itself. Without mandatory opening, pipeline companies have in fact the exclusivity of the physical infrastructure. Exclusivity means that the pipeline owner has the exclusive and unrestricted right to capacity access of the pipeline for gas marketing. Such exclusivity should be limited in time, however, to encourage efficient use and future competition: if the pipeline owner cannot fully utilise its capacity after several years, it should open to TPA through bilateral negotiations.

The exclusivity of the route itself is not desirable. It is not needed if an economically viable parallel pipeline can be built without compromising the economics of the existing one. A second pipeline is unlikely to be built over a given route soon after the first one is built, unless capacity in the first line is filled quickly. Even in this case, the incumbent company would still have the natural advantage to expand capacity through looping or by building a parallel line. It does not need protection by having exclusivity on the route.

Exclusive rights for high-pressure transmission in a given geographical area would also be undesirable. In practice, geographical exclusivity would also be difficult to achieve, as one gas basin can supply several cities and one city can have several supply sources. Without geographical exclusivity, the incumbent transmission company would also have a greater incentive to provide efficient and effective service in the long run to prevent competition for the market by a potential new entrant. The development of an interconnected gas transmission network would also complicate the definition of exclusive rights, and could hinder the construction of new lines.

Encouraging competition in building pipelines should be a priority in pipeline regulation. To achieve this, the government should not give preference to state companies in assessing applications to develop new transmission pipeline projects. It should also remove the *de facto* monopoly rights over gas transmission that state-owned companies currently enjoy. This would enhance incentives for companies to lower costs and improve the quality of service. Currently, high-pressure transmission is mainly in the hands of PetroChina and CNOOC, although their activities are on a very limited scale. CNOOC has already built several offshore transmission lines with foreign companies (Arco in the South China Sea and Shenergy & Sinopec Star in the East China Sea). PetroChina and its partners are now building the West-East Pipeline. SINOPEC will also start to build high-pressure transmission lines. These developments should lead to competition in bidding for pipeline concessions. Pipeline operators should be appropriately rewarded for efficiency gains in pipeline operations.

Exclusivity in LNG facilities

In the same way as for pipelines, the exclusivity for an LNG terminal should be granted to its owner within a given period, after which it should be open for TPA. The owner of the existing LNG terminal would also have a natural right for capacity expansion and does not need geographical exclusivity.

The legislation on access to LNG terminals is determinant for the building of new terminals. In Europe, the current proposals within the framework of the EU Gas Directive require LNG-receiving terminals to be subject to regulated TPA. However, this raises the question of the financing of new terminals in the future. Italy is the first country that has adopted a specific legislation to foster new investments in LNG terminals, allowing for a priority of access (up to 80% of the total capacity and up to 20 years) by the sponsor to the new terminal. It also allows for a higher rate of return on LNG terminals than the rate applicable to gas transmission networks.

Regulating local distribution

Regulation at the distribution level may be necessary, as it is difficult and costly to duplicate distribution lines and therefore they can be considered as a natural monopoly.

- There are two key elements in the regulation of the gas distribution sector:
- The first is the concession or franchise, which typically gives the distribution companies an exclusive right to distribute gas in specified areas and for a given period, in return for which the distribution companies have the obligation to supply those areas with certain quality standards and conditions.
- The second key element is price regulation, especially for small, captive consumers, that is, those who have no choice of supplier or very limited ability of fuel switching. Pricing regulation has been discussed in Chapter 6. The following text discusses concession terms.

Gas distribution is often the subject of regulation, not only in price-setting for captive consumers, but also because distribution uses public lands and involves important safety and security issues. Gas distribution is often considered as a natural monopoly, but this is not entirely true. In fact, only the physical distribution of gas is, not the gas supply, which consists of purchasing, marketing, billing and providing a range of related services. This is an important distinction, because it is the basis for introducing more competition through the possible unbundling of the two activities.

A prerequisite for more competition is to allow private investors to invest in the gas distribution business. Only when private investors are involved, will concession agreements with the municipality be needed. While there is a need to provide a concession to a private gas company with the monopoly right of distribution (both supply and transport) in a specified area, there should be continuous pressure for companies to compete, at regular intervals, for the concession. This could be organised through a competitive bidding process, such as the case in Mexico (Box 11.5). It should be open to all, including bidders from other cities and foreign companies, and the selection procedure should be transparent and non-discriminatory against outsiders. This involves the establishment of an effective bidding process with a straightforward and transparent bidding procedure. Consideration also needs to be given to the potential transfer of the management of the infrastructure at the end of the concession. The incumbents should be provided with sufficient incentive to maintain the assets in good condition and to expand them if the opportunities and the need exist.

Box 11.5

Mexico's Concession System

In Mexico, concessions for gas distribution are granted through a two-step competitive bidding procedure and the winner is granted a 12-year exclusive period. The bidding procedure is launched by the regulator when there are sufficient factors to justify the development of a distribution project, or as a result of stated interest from an interested party. Bidders must meet certain conditions that define minimum coverage, technical specifications, safety standards and quality of service. The bidding procedure involves two evaluations: one technical and one economic. The technical evaluation is done on a "pass" or "fail" basis; no ranking is made between the proposals. The main criterion for the economic evaluation is the tariff for the service offered, defined as the maximum average revenue yield per unit that the company can obtain in the first five years of operation. This revenue yield will be used as the initial value for the proposed price cap regulation. All proposals within a 10% difference from the lowest tariff will be declared as tied, in which case the winning proposal is the one with the highest coverage. Coverage is defined as the number of users that the bidder expects to be connected to the system in the first five years.

Source: Natural Gas Distribution Study, IEA, 1998.

As noted earlier, large industrial consumers, such as power generators, are typically supplied directly by pipeline companies, but the borderline with local distribution is not very clear. It is a subject for the government to decide. If large consumers are supplied directly by pipeline companies, these should be explicitly excluded from the distribution concession.

In conclusion, it makes sense to confer exclusive rights to companies to distribute and market gas within pre-defined geographical areas. These rights could be provided through concession agreements with the national and provincial authorities. The concessions for the physical distribution of gas would normally cover a given period, depending on the time needed to recover the investment. Exclusive rights for the supply of gas within a designated area should be of shorter duration than the distribution rights, to allow for the introduction of gas-to-gas competition in the medium-term.

To facilitate the concession process and to avoid significant disparities in concession agreements between cities, it may be worthwhile for China to set up a model concession agreement, which should be drafted on the basis of the experience of a few cities and used as a reference for others. The model agreement could include a number of rules in terms of obligations for supply, connection and delivery conditions, tariff-setting and investment criteria for network extensions. It could also specify the range of duration for the concession, the possible exclusion of large consumers beyond a certain size, and other key provisions.

For the elaboration and implementation of concession agreements between municipal governments and distribution companies, a legal framework for downstream activities is highly desirable.

RECOMMENDATIONS

Based on the above analyses, the following key recommendations are formulated:

RECOMMENDATIONS ON POLICY-MAKING, STRUCTURE AND REGULATION

The Chinese government should:

- Publish a white paper on natural gas market development, setting out clearly the government's policy objectives and long-term strategy for the development of the industry.
- Prepare a national framework law on natural gas to provide the legal basis for all gas activities downstream of production.
- Effectively and completely remove policy-making and regulatory functions from state-owned energy companies.
- Establish a specialist national energy department, initially responsible for both energy policy-making and industry regulation. Establish, in the medium term, a national regulatory agency for the gas industry, independent from the government, with sufficient resources, accurate data and adequate analytical ability.
- Put in place as soon as possible a set of regulations on health, safety and environmental impacts, as well as technical standards for the gas industry.
- Focus on establishing a framework conducive to investment in gas pipelines, and introducing competition for building new pipelines (through bidding, for instance), while setting the stage for future competition in the use of these pipelines.
- Develop a model concession agreement based on the experience of a few cities in gas distribution concessions.
- Allow for exclusive rights of companies to use their own transportation and LNG facilities within a limited duration, and for exclusive supply *via* local distribution networks for captive customers, also within a limited duration.

ANNEXES

CHINA'S ENVIRONMENTAL LAWS AND REGULATIONS RELATED TO AIR POLLUTION

ENVIRONMENTAL LAWS

China's legal framework for environmental protection started in 1979, with the promulgation of the**"Environmental Protection Law for Trial Implementation**". This first environmental legislation required polluters to comply with pollution and waste discharge standards, directed enterprises to assess environmental impacts of proposed projects and ensured that new projects satisfy applicable environmental standards. It also established national and local environmental agencies. Following a ten-year trial period, the formal "**Environmental Protection Law"** came into effect in 1989. This legal act constitutes a basis for China's environmental protection system.

In 1987, China introduced its **Air Pollution Prevention and Control Law**. It was amended in 1995. The main amendment is the addition of articles on SO_2 pollution and acid rain control, as the law created "acid rain control regions" and "sulphur dioxide pollution control regions" in China. With the mapping out of these areas (1.09 million square kilometres representing 11.4% of national total land), special control and prevention had to be intensified. Provincial and municipal governments were allowed to set more stringent rules than those applied to their jurisdictions by the central government. On April 29, 2000, the new **"Air Pollution Prevention and Control Law"** was promulgated. Compared with the 1995 version, the number of statutes was increased from 52 to 72 and half of them have been revised. The new Law has 7 Chapters, one more than the 1995 version. The additional chapter deals with "vehicle and ship emission prevention and control".

The major amendments of the 2000 version are listed below:

- Establish the total control system and discharge permit system.
- The Discharge Permit System is a legal system stipulated in Article 15, Chapter 2 of the Law. It states: "Local people's governments in the designated zones of total control of air pollution check and ratify total emissions quotas of major air pollutants from enterprises and facilities, and issue discharge permits according to the conditions and procedures set by the State Council and based on the principle of transparency, equity and justice". Moreover, "Enterprises and facilities, who emit pollutants and have the assignment of total control air pollution, must behave according to the ratified emission quota and emission condition prescribed in the discharge permit".
- Clear and define the fact that pollution discharge exceeding relevant discharge standards is a violation of the law.
- The 48th statute stipulates that those that exceed the national and local environmental standards should take action to control the pollution within the time limits and should be fined no less than 10,000 RMB (and no more than 100,000 RMB).

- Establish the charge rates based on total pollutant discharge.
- The fee system needs to be adjusted to play its due role, and promote the realisation of total volume control. The new law puts forward some concrete stipulations such as setting fee rates higher than treatment cost.
- Focus on air pollution prevention and control in major cities.
- The newly modified law spells out regulations for all cities to control air pollution and demands that key cities improve atmospheric environment according to a time schedule.
- Strengthen the control of pollution from vehicles.
- With the number of vehicles and ships being increased, their emissions have caused more and more environmental impacts. The newly revised law has a new chapter with clear statements on this issue.
- Strengthen the control of urban dust pollution.
- The 43rd statute stipulates that large-scale construction and other working units, which cause flying dust in urban areas, should take measures to control flying dust, according to the regulations of local EPB.
- Control SO_2 on heat-power generation plants.
- Chapter 3 spells out specific stipulations: controlling measures for both concentration and total volume of SO_2, stricter requirements as for the new heat and power generation plants, etc.
- Control ozone-depleting substances.
- Producers and consumers, particularly of halon 1211, that exceed the ratified quotas approved by the administrative agencies of the State Council would be fined from 20,000 to 200,000 RMB. Those that violate this clause will have their quotas of production and import cancelled.
- Intensify legal liabilities.
- Counter-measures or punishments have to be legalised for environmental law violations.

REGULATIONS RELATED TO AIR POLLUTION

The State Council, the State General Administration for Environmental Protection (SEPA) and other state agencies issued numerous administrative regulations to implement environmental policies stipulated in the basic and special environmental laws. Many of the priority environmental problems are the subject of national plans and programmes. Several of China's environmental programmes are tied to international agreements, such as the "Country Programme for the Phase-out of Ozone Depleting Substances under the Montreal Protocol".

The National Ambient Air Quality Standards (NAAQS) were fist established in 1982 (Regulation GB 3095-82), and revised in 1996. They were promulgated to address the deteriorating urban air environment and set maximum allowable ambient pollution concentrations. They cover total suspended particulate (TSP), particulate matter for particles with less than 10 microns in aerodynamic diameter (PM_{10}), sulphur dioxide (SO_2), nitrogen oxides (NOx), carbon monoxide (CO) and ozone (O_3).

Six sets of **Discharge Standards** series have been promulgated:

- Comprehensive Discharge Standards for Air Pollutants (GB16297-1996)
- Discharge Standards on Boilers for Air Pollutants (GB13271-91)
- Discharge Standards on Cement Factories for Air Pollutants (GB4915-1996)
- Discharge Standards on Industrial Kilns for Air Pollutants (GB9078-1996)
- Discharge Standards on Coke Plants for Air Pollutants (GB16171-1996)
- Discharge Standards on Thermal-Power Plants for Air Pollutants (GB13223-1996).

The standards name three categories for different types of areas:

- Class 1 standards are the most stringent standards and apply to national nature reserves, tourist and historic areas, and conservation sites;
- Class 2 standards apply to residential, commercial traffic, cultural, ordinary industrial and rural zones; and
- Class 3 standards apply to specific industrial areas.

In Table A1.1, the ambient air standards proscribed by the 1996 NAAQS are compared to international guidelines set by the World Health Organisation and the World Bank. Table A1.2 shows the evolution of ambient air quality in China since 1990.

Table A1.1

Ambient Air Quality Standards (micrograms per cubic meter)

Pollutant	Sampling period	China Class 1	China Class 2	China Class 3	WHO	World Bank
TSP	Daily Mean	120	300	500	150-230[1]	110
	Annual Mean	80	200	300	60-90	70
PM_{10}	Daily Mean	50	150	250	70	–
	Annual Mean	10	100	150	–	–
SO_2	Daily Mean	50	150	250	–	125
	Annual Mean	20	60	100	40-60	50
NOx	Hourly	150	150	700	–	–
	Daily Mean	100	100	150	150	150
	Annual Mean	50	50	100	–	–
CO	Hourly	150	150	300	–	–
	Daily Mean	4,000	4,000	6,000	10,000[2]	10,000[2]
	One Hour Average	10,000	10,000	20,000	30,000	30,000
O_3	One Hour Average	120	160	200	100-120	–

Source: World Bank.

1 8-hour average.

Table A1.2

Evolution of Ambient Air Quality in China 1990-199
(micrograms per cubic meter)

	1990	1995	1999
TPS	327	322	330
SO_2	65	61	71
NOx	26	30	33

Source: China National Environmental Monitoring Centre.

The acid rain problem started to draw attention at the beginning of the 1990s, with action lines formulated in the **Suggestion on Acid Rain Control,** which was passed in December 1990. In 1992, the State Council decided to conduct experiments for a comprehensive treatment of acid rain, and a levy collection system for SO_2 discharge was put into operation in Guizhou and Guangdong provinces, and in the cities of Liuzhou, Nanning, Guilin, Hangzhou, Qingdao, Chongqing, Changsha, Yichang and Yibin in 1993-94.

On January 1, 1998, SO_2 emission fees (150 to 200 RMB per ton of sulphur dioxide emitted) were extended from two provinces and nine cities to all acid rain-control and SO_2 pollution-control zones[3], following the **State Council Circular on Acid Rain and Sulphur Dioxide Pollution Control Areas** (see Figure A1.1). In contrast with the pollution levy system[4], SO_2 charges apply to the total quantity of emissions, not just those in excess of regulations. A few city governments have also begun trial implementation of SO_2 emission trading schemes.

In 1998, the State Environmental Protection Agency (SEPA) formulated the **Action Plan for the Two Controlled Areas**. The action plan requires the governments at provincial (autonomous region, direct municipalities), city, and regional levels to formulate their own comprehensive plans for SO_2 control, and the national power sector authorities to establish a total volume control programme on SO_2 for the years 2005 to 2010 with the power sectors. Specific pollution control measures in these two areas include:

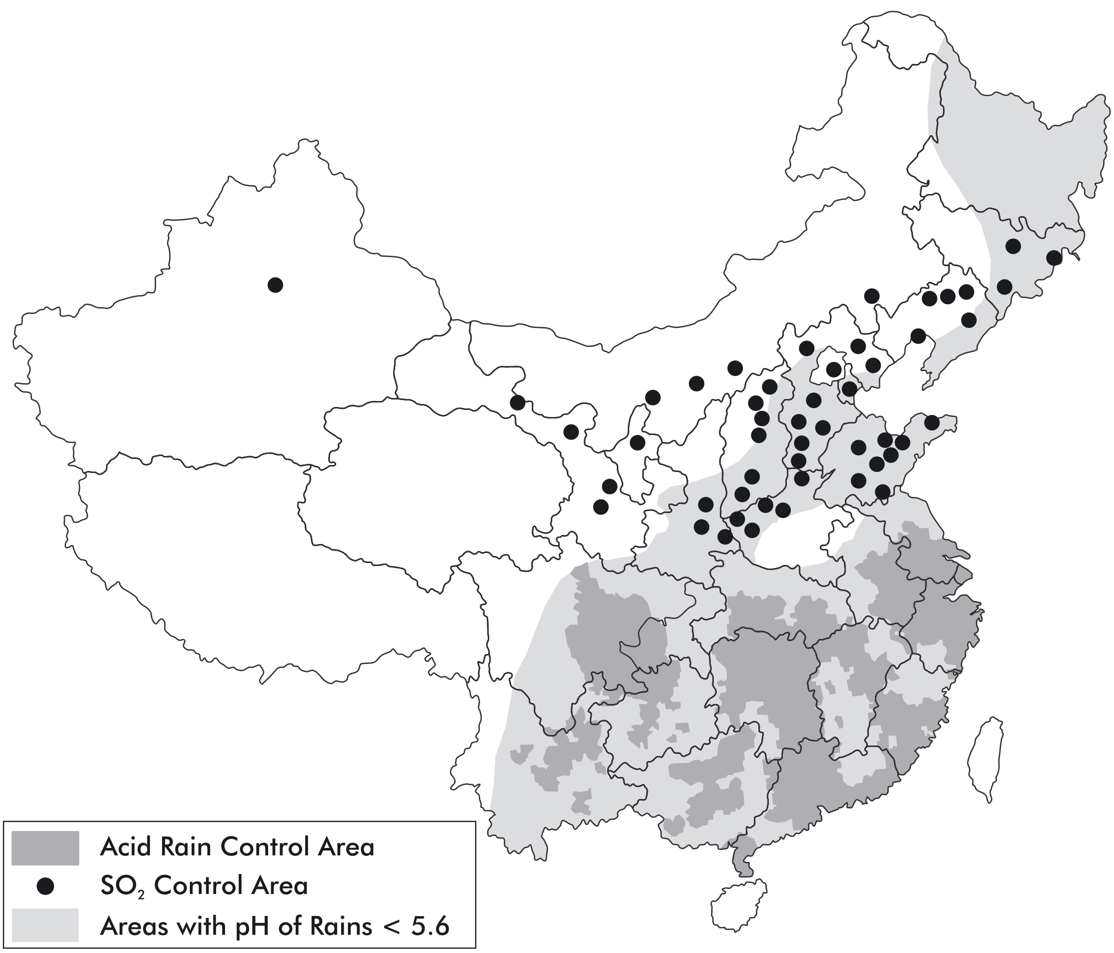
- It is not allowed to give approval to any new coal-mining project for sulphur content higher than 3%.
- For already existing coal mines, if the content of sulphur is higher than 4%, some of them (if conditions allow) should be closed down; if the content is higher than 3%, production has to be limited.
- If the content of sulphur is higher than 1.5%, corresponding scaled coal washing equipment has to be installed for new construction, retrofitting, or production expansion.
- For already existing coal mines with a sulphur content higher than 2%, coal washing and selection facilities have to be installed.

3 Except for counties on the government's poverty relief list.
4 A pollution levy system has been in effect since 1982, which applies to emissions in excess of regulations.

- Departments of planning and transportation should give priority to low-content coal, and fine-washed coal should be moved to areas with high sulphur content coal.
- It is not allowed to import any fuels with a sulphur content higher than 2%, or any coal with a content higher than 1%.
- For new construction and expansion or retrofitting of power plants, desulphurisation facilities have to be installed if the content of sulphur is higher than 1%. If the content is higher than 1%, measures had to be undertaken before the year 2000 to reduce the discharge of SO_2. Before 2010, the corresponding facilities for desulphurisation have to be in place by stages, or relevant measures have to undertaken to reduce the discharge of SO_2.
- Industrial boilers and kilns have to meet the standards before 2000.
- Pollution sources of SO_2 will be charged for their discharges.
- By the year 2000, households are no longer allowed to burn coal.

Figure A1.1

Areas Covered by Acid Rain and SO_2 Control in China



SUMMARY OF LAWS AND REGULATIONS GOVERNING OIL AND GAS ACTIVITIES IN CHINA[1]

THE MINERAL RESOURCES LAW

Adopted on 19 March 1986 as amended on 29 August 1996.
Contains 47 articles.

Objective

- To develop the mining industry;
- To promote exploration, exploitation and protection of mineral resources; and
- To ensure the present and long-term national requirements for minerals.

Key points

- Applicable to all mineral resources development in China (art. 2);
- Mineral resources owned by the State; and anyone wishing to conduct mining activity must make a registration (art. 3);
- State-owned enterprises will be the principal force in mining; the state will encourage collective enterprises; and the state will direct and supervise individuals in mining activities (art. 4);
- Mineral resources are to be mined with compensation to the state (art. 5);
- State to adopt a unified registration system for mineral development (art. 10);
- No mining activities in special areas such as harbours, ports, railways, important rivers (art. 17);
- Mine closure requires a report on mining operations, hidden dangers, environmental protection etc. (art. 18);
- Comprehensive assessment report is required for general survey of mineral resources (art. 21);
- Original data, samples, specimens etc. should be protected and preserved (art. 24);
- Mineral exploitation must be conducted in conformity with state provisions on labour safety, and environmental protection (arts. 29 and 30);

1 This summary mainly relies on the report on "Energy Policy and Structure in the People's Republic of China". The report was prepared in 1999 by the Centre for Energy, Petroleum and Mineral Law and Policy of the University of Dundee, Scotland; the International Centre for Energy and Environmental Technology in co-operation with the Rhine Westphalia Institute of Economic Research, Germany; and the Institute of Nuclear Energy Technology of Tsinghua University, China. It was jointly funded by the European Commission and China's Ministry of Science and Technology.

- Construction of railways, factories, and oil pipelines must obtain information from geology and mineral departments (art. 31);
- The state shall direct and help collective enterprises and individual miners to raise their technical levels (art. 34);
- Illegal mining shall be ordered to stop excavation, compensate for the losses caused (art. 39);
- Mining beyond the license area shall be ordered to return to the approved area and the unlawful proceeds confiscated and fined concurrently (art. 40);
- Stealing and seizing mineral products or other property of mining enterprises shall be subject to investigation for criminal responsibility (art. 41);
- Unlawful proceeds from sale, lease and transfer of mineral resources shall be confiscated, and perpetrators subject to fines (art. 42);
- Exploitation of mineral resources in violation of this law shall be ordered to compensate for losses caused, and subject to fines Serious offences will result in revocation of the license (art.44);
- Disputes over the limits of mining areas between mining enterprises shall be settled by the parties through consultation; if no agreement is reached, the matter shall be handled and settled by the relevant local and central government agencies (art. 47).

Significance

- First law to cover mineral resources, including oil and gas, and their development, and
- Applicable to foreign investment in the mining sector.

RULES ON IMPLEMENTATION OF THE MINERAL RESOURCES LAW

Promulgated and came into effect on 26 March 1996.
The rules contain 46 articles.

Objectives

- To implement the Mineral Resources Law, and
- To strengthen the regulation over mineral exploration and development.

Key Points

- Mineral resources defined as the natural resources formed under geological forces and in solid, liquid or gaseous states (art. 2);
- Mineral resources belong to the state and its ownership will not change by the alteration of the land ownership or the land use right, and the State Council represents the state in exercising the mineral ownership (art. 3);
- Exploration and development require licenses (art. 5);
- Foreign companies, enterprises and other economic organisations and individuals are allowed to invest in the mineral sector (art. 76);

- Mineral authority at the central level is responsible for supervision and administration of mineral development across the country; mineral departments at the provincial and autonomous region level are responsible for activities taking place within their domains (art. 8);
- Exploration of mineral resources shall apply for approval and registration (art. 9);
- Application for individual ownership of mines shall meet certain conditions including financial and technical capabilities (art. 14);
- Mineral rights holders shall have the following rights and interests:
  - mine the area,
  - install power, supply, and communication facilities within and adjacent to the mining area,
  - right of passage and way,
  - right to use the land,
  - autonomous sales of mineral products (art 16);
- Mining rights holders shall have the following obligations:
  - start and finish the work within time limits,
  - make comprehensive exploration and assessment of the area,
  - compile and submit mineral reports,
  - observe the laws and regulations on labour, safety, and environmental protection (art.17);
- Exploration reports and other valuable data will be used with financial compensation (art.20);
- Disputes shall be reconciled through consultation; failing reconciliation, the case will be referred to arbitration by the mineral authority (art. 23);
- Mineral development rights holders shall have the following rights and obligations:
  - conduct development activities,
  - free sale of production; construct production and living facilities,
  - obtain land use rights,
  - effectively protect, rationally and comprehensively develop and use the mineral resources,
  - pay mineral taxes,
  - observe the relevant laws and regulations (arts. 31 and 32);
- State protects the legitimate rights and interests of collective and private miners (art. 37);
- Collective miners may mine the mineral deposits or spots not suitable for state development (art. 38);
- Individual miners may excavate scattered and small deposits or spots (art 40);
- Mining without a license will be subject to a fine of up to half of the illegal proceeds:
  - mining beyond the approved scope will be subject to a fine of up to 30% of illegal proceeds,
  - illegal transfer of license or rights will result in a fine of up to 100% of the illegal proceeds,
  - mortgaging mineral rights will be subject to a fine of 500 RMB,

- trading of minerals in violation of state regulations will be subject to a fine of up to 100% of illegal proceeds,
- destructive mining will be subject to a fine of up to 50% of the value of lost minerals,
- improper issue of licenses will result in administrative and even criminal penalties (art. 43).

Significance

- Provide for the first time a set of procedures and rules for application, approval of exploration and production rights;
- Provide a penalty system against various violations; and
- All provisions seemingly applicable to foreign investors.

REGULATIONS ON TRANSFER OF EXPLORATION AND MINING RIGHTS

Promulgated and came into effect on 12 February 1998.
The regulations contain 18 articles.

Objectives

- To strengthen the administration of transfer of prospecting and mining rights;
- To protect the lawful rights and interests of the title holder; and
- To promote the development of the mining industry.

Key Points

- Applicable to transfer of any mining rights (art. 2);
- Transfer of mining rights is not permissible except under certain circumstances (art. 3);
- Transfer of exploration license must meet the following requirements:
  - elapse of 2 years or more or discovery of mineral reserve,
  - fulfillment of the minimum exploration expenditure,
  - undisputed ownership of exploration rights,
  - full payment of exploration fee or any reimbursement fee (art. 5);
- Transfer of mining rights must meet the following requirements:
  - passage of one or more years since the commencement of mining,
  - undisputed ownership of mining rights,
  - full payment of mining fee or any reimbursement fee (art. 6);
- Materials required:
  - application,
  - evidence of qualification of the assignee,
  - evidence of having met all the requirements for transfer,
  - status report on the exploration or mining project (art. 8);
- Approval or rejection will be done within 40 days (art. 10);
- Rights and obligations will be transferred to assignees upon approval of application (art. 12);
- Assignees will assume whatever time period remains on the original licenses (art 13);

- Proceeds from unauthorised or illegal transfers shall be subject to confiscation, and a fine of up to 100,000 RMB will be imposed; serious violation will result in revocation of the license (arts. 14 & 15);
- Negligence, abuse of power, and other serious violations by civil servants will be subject to investigation, administrative and criminal penalties (art. 16).

Significance

- These regulations provide for the first time a set of procedures and rules for application, approval and transfer of exploration and production rights under mining licenses in the extractive industries in China.

REGULATIONS ON REGISTRATION OVER MINERAL RESOURCES EXPLORATION

Issued and came into effect on 19 February 1998.
Contain 42 articles and a short appendix listing 34 types of mineral resources.

Objective

- To strengthen the administration of mineral resources exploration;
- To safeguard the lawful rights and interests of exploration licensees;
- To maintain the exploration order; and
- To promote the wise development of the mining industry.

Key Points

- Adopt a Unified Block Registration System based on a grid pattern of longitude 1’ x latitude 1’ (art. 2),
- Largest area for each exploration project is as follows:
  - 10 blocks for mineral water,
  - 40 blocks for metal and non-metal minerals,
  - 200 blocks for coal, vapour minerals etc.,
  - 25,000 for petroleum and gas (art. 2);
- Contributors of prospecting funds shall be the applicant for mineral exploration rights (art. 5);
- Application should include the following documents:
  - application form,
  - certificate of qualification,
  - exploration work plan,
  - implementation proposal,
  - proof of financial capability,
  - a Legal Person Certificate if applying for oil and gas exploration (art 6);
- Application will be reviewed on a first come first served basis, and a decision made within 40 days (art 8);

- Exploration license valid for no more than 3 years, but up to 7 years for oil and gas exploration (art. 10);
- Exploration fee as follows:
  - 100 RMB p/s for first three years,
  - 100 RMB added p/y starting from the 4th year (art. 12);
- Reimbursement fee for prior state investment (art. 13);
- Minimum expenditure for exploration:
  - 2,000 RMB p/km^2 for 1st year,
  - 5,000 RMB for 2nd year,
  - 10,000 after end of 3rd year (art. 17);
- Begin work 6 months after issue of the contract;
- Experimental mining for 1 year after approval (art. 20);
- Exploration right may be reserved but not exceeding 2 years (art 21);
- 90 days waiting term before one can apply to explore the same block (art. 24);
- Violation of the regulations and the respective penalties for unilateral prospecting without a permit, exploration beyond the approved zone, illegal printing of licenses; and a concurrent fine up to 100,000 RMB may be imposed (arts. 26 and 27);
- Priority will be given to provisions in other laws on foreign investment in mineral exploration (art. 36);
- The regulations will be applied retrospectively, and the exploration fee and minimum expenditure will roll back to the 1st year and be calculated and collected accordingly (art. 38).

Significance

- Consolidated and replaced all previous provisional measures regarding exploration licenses;
- Standardised and publicised exploration licensing procedure; and
- Introduction of new financial burdens on the industry including foreign investors.

REGULATIONS ON REGISTRATION OVER MINERAL RESOURCES EXPLOITATION

Issued on 23 February 1998.
Came into force on the same day of promulgation.
Contain 33 articles and an appendix listing 34 types of mineral resources.

Objectives

- To strengthen the administration of mineral mining;
- To safeguard the lawful rights and interest of concessionaires; and
- To maintain mining order and promote sound development of the mining industry.

Key Points

- Applicable to mining of all mineral resources (art. 2);

- Mining firms must obtain licenses in order to extract mineral resources;
- Oil and gas development shall be examined and approved by the petroleum authority and then registered and licensed by the mineral resources authority (art. 3);
- Application for mining licenses should include materials as follows:
  - application form and area map,
  - evidence of qualification of the applicant,
  - development plan and utilisation proposal,
  - environmental impact assessment report,
  - in case of oil and gas application, the Enterprise Legal Person Certificate (art. 5);
- Decision on approval or rejection will be made within 40 days of receipt; applicants will pay mining fee or reimbursement fee within 30 days of approval (art. 6);
- Term of the license is 30 years for large-scale mines, 20 years for medium-scale mines, and 10 years for small mines (art. 7);
- Standard annual rental fee is 1,000 RMB per km^2 p/y (art. 9);
- A reimbursement fee for mining mineral deposits that have been discovered at the state's expense will be charged, and this fee may be paid in full or in installments (art. 10);
- Mining fee or reimbursement fee may be reduced or exempted under some circumstances including frontier mining area, mineral resources urgently needed by the state, *force majeure* such as natural disaster, etc. (Art. 12);
- Mining rights may also be obtained through public bidding (art. 13);
- Operators should apply for a permit to suspend or close down mines 30 days prior to such a decision (art. 16);
- Violation of these regulations will result in a warning, and/or a fine up to 50,000 RMB; mining license will be revoked for serious violations (art. 18);
- Damage or unauthorised removal of land markers and demarcation posts is subject to fines of up to 30,000 RMB (art. 19);
- Illegal proceeds from counterfeiting mining licenses shall be confiscated, plus a fine of up to 100,000 RMB. Serious violations will be investigated for criminal responsibilities (art. 20);
- An overdue fine on the amount in default of mining fees shall be charged at 2% p/d (art. 21);
- Reapplication for a mining license is not permissible within 2 years of revocation (art. 23);
- Existing operators shall start to pay the mining fee from the date of promulgation of the regulations (art. 29);
- These regulations will replace all previous administrative decisions and interim measures on mining registration (art. 33).

Significance

- Consolidated and replaced all previous interim measures regarding mining licenses,
- Standardised and publicised mining licensing procedure;
- Introduction of new financial burdens on the industry and foreign investors; and
- Not entirely clear whether the provisions will be applied to existing petroleum investment.

REGULATIONS ON THE EXPLOITATION OF OFFSHORE PETROLEUM RESOURCES IN CO-OPERATION WITH FOREIGN ENTERPRISES

Adopted on 12 January 1982.
Promulgated and came into effect on 30 January 1982. Revised in September 2001.
The revised version contains 27 articles.

Objective

- To safeguard national sovereignty and economic interests,
- To develop the national economy and expanding international economic and technical corporations; and
- To permit foreign participation in offshore petroleum development.

Key Points

- All petroleum resources in waters under Chinese jurisdiction are owned by PRC (Article 2);
- Chinese government shall protect foreign investments, their profits, legitimate rights and interests, and the co-operative exploitation activities (Article 3);
- All offshore petroleum activities and enterprises and persons shall be subject to Chinese law and jurisdiction (Article 3);
- The state shall not tax the investment and gains of foreign companies that are engaged in offshore oil exploration. Under some special circumstances, it can levy on the shared oil of these companies according to relevant laws and provide them with corresponding compensation (Article 4);
- China National Offshore Oil Corporation (CNOOC) shall have the overall responsibility for offshore exploitation in co-operation with foreign enterprises (Article 6);
- CNOOC is a state company incorporated in China and shall have the exclusive right to explore for, develop, produce and market the petroleum from the offshore area (Article 6);
- CNOOC shall co-operate with foreign enterprises by means of calling for bids and signing petroleum contracts; all contracts signed by CNOOC shall be subject to approval by the Ministry of Foreign Trade and Economic Co-operation (Article 7);
- Foreign companies shall be responsible for providing the investment, carrying out the operations until CNOOC takes over the production operations; in return, they may recover their investment and expenses and receive remuneration out of the petroleum produced (Article 8);
- Foreign companies may export their production, the share they purchased, and remit abroad profits and other legitimate income (Article 9);
- All enterprises, both Chinese and foreign, shall pay relevant taxes and fees, and all employees shall pay individual income taxes (Article 10);
- Petroleum equipment and materials shall be subject to tax at a reduced rate, or exempted from tax, or given other preferential tax treatment (Article 11);
- Foreign contractors shall open a bank account in foreign exchange currency according to relevant regulations (Article 12);

- Foreign contractors may hire the appropriate number of staff; they may give preference in employment to Chinese personnel (Article 13);
- Foreign contractors must report to CNOOC on petroleum operations, and must submit necessary data and samples (Article 14);
- The operator must formulate an overall development programme with the objective of maximising the oil recovery (Article 17);
- Foreign contractors must use the existing supply bases, and new bases if necessary must be established within the territory of China with the approval of CNOOC (Article 18);
- CNOOC shall have the right to send its personnel to a joint foreign contractor in making master designs and engineering designs (Article 19);
- Petroleum equipment purchased and owned by foreign contractors shall belong to CNOOC after cost has been recovered (Article 20);
- CNOOC shall have the ownership of all records, samples, and other original data (Article 21);
- Operator and subcontractors must comply with laws and regulations on environmental protection and safety, and protect fisheries and other natural resources (Article 22);
- Petroleum produced may be landed in China or, upon approval, exported from offshore terminals (Article 23);
- Disputes shall be settled through friendly consultation; mediation and arbitration may be conducted by a Chinese arbitration body or a foreign one (Article 24);
- A warning or a deadline for correction will be issued against violations of these provisions; the competent authority of China shall have the right to adopt necessary measures, even to the extent of suspending operations. Serious violations will be subject to fines and law suits (Article 25);

Significance

- The first petroleum law of the country;
- Serves as the charter for CNOOC;
- Provides the institutional infrastructure to deal with foreign companies; and
- Lays down the legal framework for Sino-foreign co-operation in offshore petroleum development.

REGULATIONS ON THE EXPLOITATION OF LAND PETROLEUM RESOURCES IN CO-OPERATION WITH FOREIGN ENTERPRISES

Promulgated and came into effect on 17 October 1992. Revised in October 2001.

Key Points

- The land petroleum regulations are, in essence, a reproduction of the offshore petroleum regulations;
- They are therefore identical not only in objective, but also in form and content;

- The only difference is that the land petroleum regulations give CNPC and SINOPEC the exclusive right to collaborate with foreign companies in the exploration and development of onshore petroleum resources.

Significance

- Before the 2001 revision, CNPC was the sole entrusted domestic company for co-operation with foreign investors. The revision made it both CNPC and SINOPEC;
- Serves as the charter for CNPC and SINOPEC;
- Encourages foreign investment in domestic exploration and development of new resources; and
- Legally opens up all petroleum provinces of China to foreign participation.

COMPETITIVENESS OF NATURAL GAS IN SHANGHAI[1]

Figure A3.1

Map of Shanghai

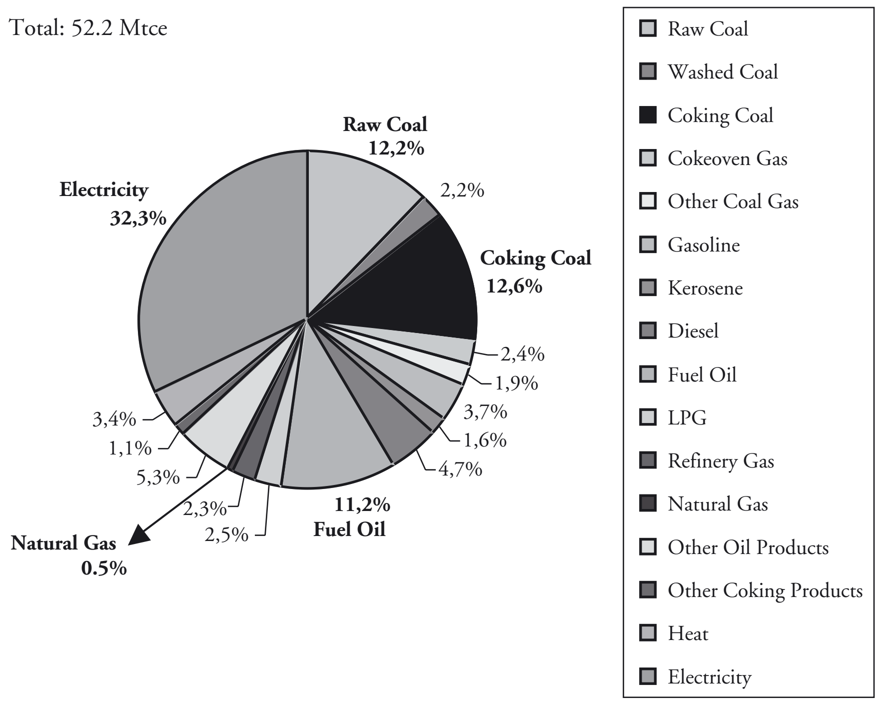
1 This Annex was contributed by the Tongji University of Shanghai, under the sponsorship of Shell. Main data were checked by the Shanghai Planning Commission, but the conclusions do not necessarily reflect the views of the Commission.

SHANGHAI'S ENERGY SITUATION

Shanghai covers an area of 6,340 square kilometres and has a population of 13.22 million. In 2000, Shanghai's GDP accounted for 5.1% of the total for the whole nation, and in 2001 its GDP per capita reached 4,180 US dollars. As a major economic centre in China, Shanghai's energy consumption remains high. Since the 1990s, Shanghai's energy demand has been increasing with the development of the economy, which resulted in an annual average rise of 5% and 7% respectively of the city's gross energy and electricity consumption.

Figure A3.2

Shanghai's Final Energy Consumption Structure in 2000



In the next 5 to 10 years, the Shanghai municipal government plans to take a number of measures in order to achieve rational, efficient, and clean uses of energy and to improve the environmental quality of the city. They include:

- Control the consumption of coal, strictly limit the scale of coal-fired power plant and coal-fired equipment, and reduce the dispersed coal burning.
- Limit the development of energy intensive and low value adding industries.
- Optimise the energy supply structure, expand the supply and utilisation of natural gas, and increase the supply of electricity from outside the city.
- Support the R&D and utilisation of renewable and new energy resources and encourage the development and application of energy-saving technologies.

- Encourage the use of high-quality energies such as electricity and gas, and balance the power supply system by reducing peak-load consumption and encouraging base-load power uses.
- Enhance the management of the petroleum industry and improve energy storage systems.
- Further deepen the reform of energy management systems and promote two important changes: a) change from a passive approach to solving energy shortage problems to actively optimising the structure of energy supply and upgrading the quality of energy; and b) change from limiting energy consumption to actively developing a high-quality energy market and to improving its service quality.

NATURAL GAS DEVELOPMENT IN SHANGHAI

In 2000, Shanghai consumed 2.1 billion cubic meters (bcm) of manufactured gas, 516 thousand tonnes of liquefied petroleum gas (LPG) and 0.25 bcm of natural gas. Over 95% of inhabitants have access to one of these three gas supply sources.

Natural gas was introduced in Shanghai in 1999 through a 375-km pipeline from the Pinghu field in the East China Sea. Within two years, its consumption doubled – from 101 million cubic metres (mcm) in 1999 to 250 mcm in 2000. The gas is mainly employed in residential use, industry, and the remaking of manufactured gas.

To ensure the security of natural gas supply and meet peak gas demand, Shanghai has built an LNG plant in the Pudong area. The facility can provide 10 days of gas supply at the current level of consumption. To provide further security of supply, the Shanghai municipal government decided to reform the equipment of the Shanghai Shidongkou Manufactured Gas Production Co. Ltd., which has been producing manufactured gas from naphtha, to produce Substitute Natural Gas (SNG). SNG is equal to natural gas in heat value and combustibility. The factory has three sets of machinery, and each produces 0.7 mcm of manufactured gas per day. One reformed set can produce 0.34 mcm of SNG per day, so the whole factory can produce 1 mcm of SNG/day in case of natural gas supply shortage. When SNG is not needed, the reformed equipment still produces manufactured gas.

Natural gas demand

Shanghai is the destination market of PetroChina's 12 bcm/y "West-East Gas Pipeline" project, which is expected to bring natural gas to Shanghai by the end of 2003, when the east section of the pipeline is completed. According to Shanghai municipal government projections, natural gas consumption could reach 3 bcm/y by 2005.

Table A3.1 provides one forecast of natural gas demand in Shanghai by end-use sectors.

Table A3.1

Shanghai Natural Gas Demand Forecast (Unit: 10^9 m^3/y)

Year	2000	2003	2005	2010	2020
City Gas	0.29	1.07	1.08	2.03	3.1
Chemicals	0	0.18	0.43	0.93	1.0
Power generation	0	0.3	1.29	2.7	4.38
Transportation	0	0.09	0.12	0.18	0.28
Total	0.29	1.64	2.92	5.84	8.76

The main consumers of city gas are residents. In recent years, housing conditions, living standards, and household gas appliances have been improved. The improvements in housing and the extension of the gas supply system make it possible for more and more residents to use gas.

The large-scale arrival of natural gas provides conditions for Shanghai to construct gas-fired power plants. According to certain forecasts, 2.4-3 GW of gas-fired power plants will be constructed within the next 10 years. The Zhabei Power Plant will be reformed, and a cogeneration unit will be built in Caojing Chemical Zone. In the longer term, more gas-fired power plants will be considered.

Natural gas supply sources

Sources of natural gas supply to Shanghai include:

East China Sea

Gas from the Pinghu field started to supply Shanghai in April 1999, but its reserve is comparatively small. The maximum capacity in the first phase is 1.2 million m^3/day. It is expected to reach 2 million m^3/day during the second phase in 2003.

Supply from the Xihu Trough, where several fields could be developed, could be very important. According to the initial exploration result, the whole area could produce up to 10 bcm/a between 2010 and 2015.

At present, Pinghu is the only natural gas source for Shanghai, especially for the Pudong area's city gas. The gas price arriving in Shanghai is 1.4 RMB/m^3, and the average market price in Shanghai is 2.1 RMB/m^3.

West-East pipeline (WEP)

The designed transportation capacity of the WEP is 12 bcm per year. The pipeline construction is divided into two sections, with the east section expected to bring natural gas to Shanghai in 2003. The SDPC has indicated that the upstream price (namely, the well price and purification fee combined) is 0.45 RMB/m^3, and the transportation fee through the long pipeline is 0.9 RMB/m^3. Therefore, the government-guiding price for Shanghai's city-gate is 1.35 RMB/m^3.

Imported liquefied natural gas (LNG)

In the long term, Shanghai can manage to import LNG by building an LNG receiving terminal in the neighbouring Zhejiang Province, which is about 70 km away. Since Shanghai is close to Japan geographically, the CIF cost of imported LNG in Shanghai can be evaluated by consulting that of imported LNG in Japan. Based on the Japanese price data, the CIF price of LNG imported to Zhejiang is about 1.105 RMB/m^3 (for regasified gas, based on the price of crude oil at 18$/barrel). Currently, there is no firm plan to import LNG to the East China region; much will depend on the gas utilisation result from the WEP.

Russia's east Siberia

Russia's east Siberia has important natural gas reserves that could be exported to China's north east, and then transported down to Shanghai. Estimation based on early 1990s data showed that the well-head price of Russian gas could be 0.21 RMB/m^3. With transportation costs on the Russian side, the border price for China could be 0.41 RMB/m^3. Domestic transportation costs within China to bring gas from the Russian border to Shanghai could add 0.7 RMB/m^3, which would make the Shanghai city-gate gas price 1.1 RMB/m^3. Currently, there is no plan to bring Russian gas to Shanghai, and there is no serious study on the economic feasibility of this option.

NATURAL GAS PRICE IN SHANGHAI

Natural gas prices are fixed by the municipal government. They are set based on the same unit calorific value price as manufactured gas.

Manufactured gas prices are composed of the gas production cost, the value-added tax (13%) and the city's add-on charges. The city's add-on charges include city construction charge, education charge, environmental protection charge, etc. They are levied at 11% of the real amount of the paid tax (the value-added tax minus the discount).

The price of manufactured gas for residential use was increased from 0.1 RMB/m^3 in 1990 to 0.9 RMB/m^3 today. For non-residential uses, the price of manufactured gas is 1.3 RMB/m^3. Despite these increases, the Shanghai Gas Company could not reverse the loss-making situation. Moreover, the municipal government poured an important amount of subsidies into the city's gas company, but the financial position of the company remains vulnerable.

Table A3.2 provides the natural gas prices from the East China Sea in Shanghai.

Table A3.2

Prices of Natural Gas in Shanghai Unit: RMB/m^3

Users	Household	Industry	As Input for Manufactured Gas	Commerce
Price	2.1	1.9-2.1	1.7	2.6

THE COMPETITIVENESS OF NATURAL GAS IN SHANGHAI

The competitiveness of natural gas very much depends on the price of natural gas *vis-à-vis* its competitive fuels. Table A3.3 provides a comparison of energy prices based on the unit heat value.

Table A3.3

Price Comparison of Energy Sources

	Market Price RMB/10^3kcal	Thermal Value	Unit Heat Price
Coal	200-400 RMB/t	5×10^6kcal/t	0.04-0.08
Heavy Oil	1000-1500RMB/t	9.5×10^6kcal/t	0.11-0.16
Light Oil	2000-3100RMB/t	1.0×10^7kcal/t	0.2-0.31
Electricity	0.61-0.75RMB/kWh	8.61×10^2 kcal/kWh	0.71-0.87
Manufactured gas	0.9-1.3RMB/m^3	3.8×10^3 kcal/ m^3	0.24-0.34
LPG	2600-3600RMB/t	1.0988×10^7 kcal/t	0.24-0.33
Natural gas from East China Sea	1.9-2.1RMB/m^3	8.5×10^3 kcal/ m^3	0.22-0.25

For residential uses

In the residential sector, natural gas competes with manufactured gas and electricity for cooking and heating water. Although there is no direct competition between natural gas and manufactured gas as the relationship between the two is rather exclusive, the relative cost plays an important role in conversion from manufactured gas to natural gas. Table A3.4 provides a comparison of the costs per unit of useful heat that takes into account the conversion efficiency of appliances.

Table A3.4

Unit Cost of Useful Energy in Residential Sector at Current Energy Prices (RMB/1000kcal)

Energy	Hot Water	Cooking
Electricity	0.747	0.788
Manufactured gas	0.309	0.449
Natural gas	0.296	0.431

Note: efficiency for gas-fired water heaters is 0.80 and that of gas-fired cookers is 0.55. The efficiency of electric water heaters is 0.95 and electric cookers is 0.9.

It can be concluded that in the residential sector, natural gas is competitive.

As automobile fuel

Based on the assumption of gasoline price at 3 RMB/kg and of natural gas price at 1.5 RMB/m^3, Table A3.5 shows the per km fuel cost of the two automobile fuels. It can be seen that compared with a gasoline-fuelled bus, a bus running on compressed natural gas (CNG) could save approximately 0.24 RMB/km. The cost of refitting a gasoline-driven automobile into one with dual fuels is between 6,000 and 10,000 RMB per vehicle. Under normal operating conditions, the refitting expenditure would be recovered within a year.

Table A3.5

Cost Comparison of Buses Running on Gasoline and Natural Gas

Fuel	Price	Run Distance	Run Price
Gasoline	3 RMB/kg	4.77 km/kg	0.63 (RMB/km)
CNG	1.5 RMB/m^3	3.86 km/m^3	0.39 (RMB/km)

In addition to the cost advantages, buses running on natural gas are much cleaner; compared with a bus running on gasoline or diesel, a CNG bus can reduce CO emissions by 97%, NOx by 39%, CO_2 by 24%, SO_2 by 90% and noise by 40%. This should further encourage the expansion of CNG buses.

As raw material for the chemical industry

In the chemical industry, natural gas competes with coal and oil as alternative inputs. Other studies show that an acceptable price of natural gas for Shanghai's chemical enterprises is 0.7-0.9 RMB/m^3, which is lower than in other uses. There will be very strong competition in the chemical industry with China's WTO membership. If gas prices are too high, domestic chemical industries cannot compete with imports which are based on cheaper well-head gas prices.

In commercial buildings

One important area of natural gas utilisation in commercial buildings in Shanghai is air-conditioning. Table A3.6 compares the costs of the following four schemes:

- Scheme A: Centrifugal cooling water unit using electricity;
- Scheme B: Direct-firing lithium bromide absorption cool-hot water unit using fuel oil;
- Scheme C: Direct-firing lithium bromide absorbing cold- and hot- water sets using coal gas;
- Scheme D: Direct-firing lithium bromide absorbing cold- and hot-water sets using natural gas.

Table A3.6

Cost Comparison of Air-Conditioning Using Different Fuels

	Scheme A (Electricity)	Scheme B (Oil)	Scheme C (Coal Gas)	Scheme D (Natural Gas)
Depreciation Costs 10^4RMB/y	14.00	13.00	12.08	12.08
Maintenance Costs 10^4RMB/y	12.6	11.7	10.88	10.88
Energy Costs 10^4RMB/y	29.79	22.31	26.24	23.31
Total Costs 10^4RMB/y	56.39	47.01	49.20	46.27

Notes:

1. Calculation conditions: In the oil boiler, take the calorific value of the fuel oil as 10,400kcal/kg, the calorific value of the coal gas as 3,800kcal/Nm^3, and the calorific value of the natural gas as 8,500kcal/Nm^3.
2. Reference prices concerned: the electricity price is 0.635 RMB/kWh, the light oil price is 2,900 RMB/t, the manufactures gas price is 1.30 RMB/Nm^3 and the natural gas price is 2.5 RMB/Nm^3.
3. Without considering the fee applying to the use of electricity, gas and natural gas (exemption in Shanghai).
4. Equipment depreciation is calculated by 18 years, and the maintenance charge is calculated according to 5% of the equipment expense.

It can be seen that when the price of natural gas is not higher than 2.5 RMB/m^3, natural gas fuelled air-conditioners are cheaper than those fuelled with electricity, oil or coal gas.

As common industrial fuel

In the industrial sector, natural gas competes with coal and heavy oil for steam raising. Table A3.7 compares the costs of producing steam at a temperature of 310 °C, and 9.8 MPa pressure by a boiler of 4 t/h capacity.

Table A3.7

Cost Comparison of Steam Production for Industrial Uses in Shanghai

	Datong Coal	Heavy Oil	NG
Fuel Thermal Value	5,200kcal/kg	9,863 kcal/kg	8,500 kcal/Nm^3
Thermal Efficiency of Boiler	75%	89%	90%
Yearly Fuel Consumption (7000h/y)	4,679 t	2,078 t	2.386 million m^3
Fuel Unit Price	0.27RMB/kg	1.7RMB/kg	2.1RMB/m^3
Yearly Fuel Cost (10^4RMB/y)	126.3	353.3	501.1
Sulphur content	0.65%	0.90%	0
SO_2 Emissions (Ton/y)	60.8	37.4	0
SO_2 Emission Costs (10^4RMB/y) (at 1.2 RMB/kg)	7.300	4.489	0
Total Cost (10^4RMB/y)	133.6	357.8	501.1

It can be seen that, at 2.1RMB/m^3, the gas-fired boiler is the most expensive compared with the other two alternatives, even when SO_2 emission charges at 1,200 RMB/ton are considered. Clearly, gas cannot compete with either coal or fuel oil for industrial steam production.

Gas for power generation

In power generation, gas competes with coal and heavy fuel oil. Two case studies are provided here to show the competitiveness of natural gas. One is the conversion of an oil-fired plant (the Shanghai Zhabei Power Plant Conversion Project) and the other is a new gas-fired unit (the Shanghai Huaneng Gas-fired Power Project).

Shanghai Zhabei power plant conversion project

This plant uses heavy fuel oil for its 4x100 MW gas turbines for peak shaving. The conversion involves the following:

- Natural gas from the West-East Pipeline will replace heavy oil as generating fuel.
- Boiler fuel remains fuel oil.
- Natural gas pressure from the main pipeline of Shanghai's natural gas network is 1.6Mpa, lower than the usual inlet gas pressure of power-generating equipment, therefore pressure boosters and regulators should be fixed at the main inlet pipe of power plants.
- Yearly operating time is assumed to be 3,000 hours and the sensitivity analysis is made at 2,500, 3,500 and 4,000 hours (the following example is based on 4,000-hours).
- Gas price is assumed at 1.1 RMB/m^3 for the power plant, and the sensitivity analysis is made at 0.9-1.5 RMB/m^3.

The total investment of this conversion project is estimated at RMB193.6 million, with US$14.5 million (RMB120.3 million) in foreign currency and the rest (RMB73.3 million) in local currency.

According to the existing regulations for peak-shaving plants, the electricity sale price to the grid is 0.89 RMB/kWh before repayment. After repayment, the network electricity power price is 0.63 RMB/kWh. The repayment period is 5 years.

Table A3.8

Fuel Cost Changes with the Prices of Heavy Oil and Natural Gas

Heavy Oil Price US$/t	Fuel Cost RMB/kWh	Natural Gas Price (RMB/m³)	Fuel Cost RMB/kWh
110	0.270	0.90	0.273
120	0.295	1.00	0.303
130	0.319	1.10	0.333
140	0.343	1.20	0.364
150	0.368	1.30	0.394
160	0.393	1.40	0.424
170	0.417	1.50	0.455
180	0.442	–	–

The fuel cost of the power plant varies with the prices of heavy oil and natural gas (Table A3.8). When the price of heavy oil is 180 US$/t, its corresponding fuel cost is 0.442 RMB/kWh. When the price of natural gas is 1.1 RMB/m^3, its corresponding fuel cost is 0.333 RMB/kWh, which is 0.109 RMB/kWh lower than the fuel cost of the oil-fired plant.

Even when the price of natural gas rises to 1.35 RMB/m^3, its corresponding fuel cost is 0.409 RMB/kWh, which is still 0.033 RMB/kWh lower than 0.442 RMB/kWh (i.e. when the price of heavy oil is 180 US$/t.) This would indicate that under the current price of crude oil (i.e. heavy oil at 180 US$/t), natural gas is more competitive than heavy oil if the gas price is below 1.35 RMB/m^3. However, this calculation does not include the investment cost related to plant conversion. To recover the conversion cost, the natural gas price would need to be much lower.

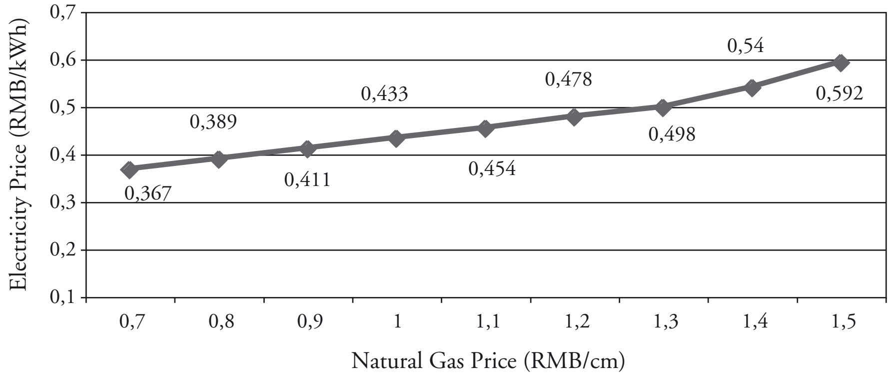
Shanghai Huaneng gas-fired power project

Shanghai Huaneng Co. plans to establish a gas-fired power plant on the site of its first phase of Shanghai No.2 Shi Dong Kou Power Plant, which is a coal-fired plant without flue-gas desulphurisation (FGD) (there is still no coal-fired plant with FGD in Shanghai as yet). The existing coal-fired plant sells electricity at about 0.31 RMB/kWh (tax not included) to the grid.

The new gas-fired power project includes three CCGT units, with a total capacity of 1,200 MW. The natural gas is to be supplied from the West East Pipeline. Figure A3.3 shows the simulated relationship between the price of natural gas and the price of electricity when the plant runs 4,000 hours a year.

Figure A3.3

Relationship between Natural Gas Price and Power Output Price



Obviously, the higher the price of natural gas, the higher the price of electricity, and the longer the plant operates, the lower the price of electricity. Even if the price of natural gas is 1.0 RMB/m^3, the CCGT plant can produce electricity at the price of 0.433 RMB/kWh, which is still much higher than the price currently paid to the coal-fired plant. This shows that, at 4,000 hours/y, natural gas cannot compete with coal-fired plants if there are no special supporting policies or measures.

Gas-fired co-generation

Gas-fired co-generation holds important potential in Shanghai. If both electricity and heat can be sold freely, that is, electricity sales to the power grid can be assured, gas-fired co-generation can compete with coal-fired. The ban on any coal-fired plant in Shanghai further strengthens the competitive advantages of gas-fired co-generation.

THE PRICE AND NON-PRICE FACTORS THAT HINDER THE WIDER USE OF NATURAL GAS IN SHANGHAI

The following factors impede the development of a natural gas market in Shanghai:

- The comparatively high price of natural gas in industrial uses. The price of natural gas that could be accepted in the chemical industry is 0.7-0.9 RMB/m^3 and in the power industry 1.1 RMB/m^3, whereas the present price of natural gas supplying industrial users is above 1.7 RMB/m^3.
- Difficulties in gas conversion. There are obvious difficulties in converting to natural gas because the fuels now used in many enterprises and institutions are coal, oil or manufactured coal gas. Those enterprises and institutions would be reluctant to convert because of technological and financial problems.
- The high cost of converting coal-fired power plants to using natural gas. The high investment for conversion and the higher cost of fuel would definitely increase the cost of electricity.

- The imperfections of relevant policies, laws and regulations. Relevant policies, laws and regulations on natural gas market development have not been set up in Shanghai, and the gas company management is in the transition towards a new market-based management style. All these may hinder the wide use of natural gas in Shanghai.

POLICIES AND MEASURES FOR THE DEVELOPMENT OF A NATURAL GAS MARKET IN SHANGHAI

In order to promote gas market development, Shanghai's municipal government has implemented a series of encouraging policies as follows:

- Elaboration of a natural gas development plan for the city.
- Formulation of mandatory policies, such as the prohibition of building coal-fired boilers inside the beltway, the gradual conversion of existing coal-fired boilers, and the ban on the construction of any new coal-fired power plants.
- Encouragement of diversified investment in the gas distribution network to support rapid development of the natural gas industry in the city. Foreign investment in the city's gas distribution network is allowed.
- Preferential taxes for companies that use natural gas.
- Subsidies for natural gas conversion. The municipal government paid for gas conversion in the Pudong area. This is the first case in China in which a municipal government wholly undertook the cost of gas conversion work.

The conversion of coal-fired boilers for gas use has been a major challenge. By the end of 2000, there were about 2,600 coal-fired boilers operating within the city's beltway. The main factors affecting the conversion of coal-fired boilers are as follows:

- Large investment cost, ranging from 400,000 to 600,000 RMB per boiler on average.
- High daily operating cost of gas, 3-4 times higher than that of coal.
- Low standard of the current yearly smoke emission charge, which is only 1/10 of desulphurising equipment investment.

To encourage conversion, Shanghai's municipal government has taken the following measures:

- All the fees for the capacity increase to natural gas boilers have been exempted since 1999 (fee applying to the use of gas was exempted in June 2001).
- The expenses for fixing the outdoor pipes of gas boilers will be covered by gas sellers.
- The price of manufactured gas for gas boilers will be reduced from 1.30 RMB/m^3 to 1.10 RMB/m^3.
- Enterprises replacing their coal boilers with gas boilers will be eligible for certain subsidies. The reconstruction allowance is 40,000 RMB per ton of steam/h for any coal boiler and industry kiln listed in the joint programme by Shanghai Municipal Environment Protection Bureau and Shanghai Municipal Economic Commission.
- Fees for SO_2 emission have been imposed since March 1, 2000 at 0.20 RMB/kg.

The municipal government has also announced the following policies and measures for boiler conversion:

- All related enterprises should make a step-by-step conversion plan. Coal-fired boilers or kilns that cannot carry out the conversion programme before the deadline will be forced to close down.
- All areas served by the natural gas distribution network should be completely equipped with gas boilers. Approval from gas operation enterprises should be required before a license is granted to boilers below 4 t/h.
- Pollutant exhaust fees will be greatly increased. Fees for SO_2 will be increased from 0.2 RMB/kg to 1.2~1.5 RMB/kg. Punitive fees will be doubly imposed on coal-fired boilers listed in the conversion programme. All the pollutant exhaust fees will be used to make up the expenses of new gas boilers.
- The price of natural gas for boilers will be allowed to fluctuate around the average 1.10 RMB/m^3, and the margin for price reduction will be enlarged with flexible prices for different subscribers.
- Within the city's beltway, all coal-fired boilers below 4 t/h (including 4 t/h) will be transformed to clean fuel boilers by the end of 2002. In the area served by gas pipes, gas boilers will replace coal-fired boilers below 1 t/h. Moreover, the construction of areas without coal will be completed within about 100 km^2 covering the downtown area, city development zone and residential district.

ENVIRONMENTAL PROTECTION MEASURES IN SHANGHAI

Environmental protection is one of the key driving forces for natural gas development in Shanghai. Air pollution in Shanghai is mainly caused by the burning of oil products and coal. The main pollutants are NOx, suspended particles, SO_2, and dust fall. Through the energy structure adjustment, Shanghai expects to effectively control air pollution resulting from the combustion of coal and oil. Table A3.9 shows the situation of air pollution in Shanghai.

Table A3.9

Test Results of NOx, Suspended Particulates, and SO_2 in the Air of Shanghai in 2000

	NOx (mg/m^3)			Suspended Particulates (mg/m^3)			SO_2 (mg/m^3)		
Quarter of the Year	City Zone	Suburb County	Whole City	City Zone	Suburb County	Whole City	City Zone	Suburb County	Whole City
1	0.095	0.031	0.057	0.162	0.128	0.155	0.053	0.005	0.024
2	0.086	0.033	0.057	0.187	0.140	0.187	0.044	0.004	0.019
3	0.068	0.027	0.047	0.124	0.098	0.128	0.038	0.003	0.020
4	0.113	0.036	0.062	0.152	0.137	0.151	0.045	0.004	0.024
Total	0.090	0.032	0.056	0.156	0.126	0.155	0.045	0.004	0.022

Shanghai is included in the country's two control-areas for SO_2 and acid rain. It is therefore subject to national regulations on the use of coal in the two control areas. In addition to national laws and regulations, Shanghai has also published a set of Municipal Environmental Protection Regulations, which are implemented by the Shanghai Municipal Environment Protection Bureau. Current efforts by the Shanghai municipal government focus on the comprehensive control of the exhaust gas of motor vehicles and the replacement of coal-burning boilers with clean energy. Pollution charges are also levied for discharges that exceed the standards. For SO_2, fees are charged based on the total volume of emissions at 0.2 RMB/kg and are collected every month. The amount of SO_2 discharge is calculated in the following way:

- If there is desulphurising installation, the calculation of the SO_2 discharge amount should be based on the actual monitored concentration.
- If there is no desulphurising installation, the calculation of the sulphur dioxide discharge amount should be based on the sulphur content obtained from the report on the fuel-quality analysis of the purchased fuel (coal, or oil products); if there is no report, the average sulphur content of the fuel in Shanghai should be taken from the Shanghai Fuel Company as the basis for calculating the discharge amount with the material balance method.

The municipal government has also taken the following other environmental control measures in this respect:

- Ban on the building of boilers and kilns that utilise highly pollutant content fuel within the inner-elevated belt way.
- Ban on the building of boilers with below ten tons specified evaporation capacity, on kilns with discharge capacity of air pollutant equivalent to that of the boilers, and on those boilers that use highly pollutant content fuels within the area between the inner and outer elevated belt way.
- Compulsory installation of necessary desulphuration and dust-extraction equipment, where no measures have been taken to control the discharge of SO_2, smoke dust, and nitrogen oxide.

In Shanghai, the license system has been implemented to control the discharge of the main exhaust fumes. Fines and penalties vary according to the violators' situation: whether they hold a discharge license, a temporary license or no license:

- If a company does not hold a discharge license and violates the regulations, the local authorities (environmental bureau of the city, district or county) should order the company to stop discharging exhaust and impose a fine from RMB10,000 to RMB100,000.
- If a company holds a discharge license but exceeds the limit of approved total discharge quantity, the local authorities should order it to reduce discharge within a certain period. In the meantime, the authorities have the right to impose a fine from RMB10,000 to RMB100,000.
- If a company holds a temporary discharge license but exceeds the limit of the approved total discharge amount, when the validity of its temporary license expires the local authorities should revoke its temporary discharge license and order it to close down.

CONCLUSIONS

Shanghai is a very dynamic city in east China. It needs clean sources of energy to fuel its continuing economic growth and to improve the quality of life of its inhabitants. Potential sources of natural gas supply for Shanghai are widely available. The main issue is the competitiveness of natural gas.

The present case study shows that, at current prices, natural gas is competitive in the residential and transportation sectors, and in commercial buildings for air conditioning. These sectors, however, do not yet represent a significant volume of gas consumption.

For other sectors, the competitiveness of natural gas depends more critically on its price. In the industrial sector, gas cannot compete with coal or heavy oil. However, the ban on coal use in industrial boilers makes gas compete only with heavy oil. For power generation, natural gas can replace oil-fired peak-shaving plants when its price is below 1.0 RMB/m^3 without special supporting policies. At this price, it can produce electricity at a price that is currently paid to a coal-fired power plant without FGD. For chemical production, natural gas is competitive if the gas price is 0.7-0.9 RMB/m^3 or lower. It is difficult for chemical plants in Shanghai that use long-distance gas or imported gas to compete with those built at the well-head in gas-rich countries.

If it relies solely on its price competitiveness to develop its market, natural gas will be essentially for small users such as residential cooking and hot water production, peak-load power production, CNG buses, and air-conditioning in commercial buildings. The market for these types of small users will take time to develop; they cannot support large-scale gas pipeline development. As a consequence, in order to develop the gas market in other sectors, there is a need for government intervention, with appropriate financial incentives, as demonstrated in the case of the compulsory conversion of coal-fired boilers to gas-fired ones.

ABBREVIATIONS

ADB	Asian Development Bank
APEC	Asia Pacific Economic Co-operation
APERC	Asia-Pacific Energy Research Centre
bcm/a or /y	Billion Cubic Meters per Annum or per Year
BOT	Build-Own-Transfer
CBM	Coal-Bed Methane
CCB	China Construction Bank
CCGT	Combined-Cycle Gas Turbines
CCHP	Combined Cooling, Heating and Power
CDB	China Development Bank
CFBC	Circulating Fluidised Bed Combustion
CHP	Combined Heat and Power
CIF	Cost Insurance Freight
cm	Cubic Metre
CNG	Compressed Natural Gas
CNOOC	China National Offshore Oil Corporation
CNPC	China National Petroleum Corporation
CNSPC	China National Star Petroleum Corporation
CO_2	Carbon Dioxide
CSRC	China Securities Regulatory Commission
DOE	US Department of Energy
ECA	Export Credit Agency
EPB	Environmental Protection Bureau
ERI	Energy Research Institute
FERC	Federal Energy Regulatory Commission
FDI	Foreign Direct Investment
FGD	Flue-gas Desulphurisation
FIE	Foreign Invested Enterprise
Fob	Free-on-Board
FSU	Former Soviet Union
FYP	Five-Year Plan
GCV	Gross Calorific Value
GDP	Gross Domestic Product
GFZSJ	Guangdong, Fujian, Zhejiang, Shanghai and Jiangsu provinces
GW	Gigawatt
HKCG	Hong Kong China Gas Company
HKCLP	Hong Kong China Light and Power Company
HSBC	Hong Kong Shanghai Bank Corporation

HSE	Health-Safety-Environmental
IEA	International Energy Agency
IESM/SCORES	Institute of Economic System and Management of the State Council's Office for Reform of Economic System
IGCC	Integrated Gasification Combined Cycle
IPO	Initial Public Offering
IPP	Independent Power Producer
IRR	Internal Rate of Return
JV	Joint Venture
kcal	Kilocalorie
KEPCO	Korea Electric Power Corporation
kg	Kilogramme
KOGAS	Korea Gas Corporation
km	Kilometre
kW	Kilowatt
kWh	Kilowatt-hour
LDC	Local Distribution Companies
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
Mb/d	Million Barrels per Day
MBTU	Million of British Thermal Unit
Mcm	Million Cubic Metres
METI	Japan's Ministry of Economy, Trade and Industry
MIGA	Multilateral Investment Guarantee Agency
MLNR	Ministry of Land and Natural Resources
MOCIE	Korea's Ministry of Commerce, Industry and Energy
MOF	Ministry of Finance
MOFTEC	Ministry of Foreign Trade and Economic Co-operation
Mpa	Million pa of Pressure, equal to 10 bar
Mtce	Million Tons of Coal Equivalent
Mt/y	Million Tons per Year
Mtoe	Million Tons of Oil Equivalent
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NAGPF	North-East Asian Gas and Pipeline Forum
NCV	Net Calorific Value
NOx	Nitrogen Oxide
NPC	National People's Congress
OECD	Organisation for Economic Co-operation and Development
p.a.	Per Annum
PFBC	Pressurized Fluidized Bed Combustion

PPP	Purchasing Power Parity
PSC	Production Sharing Contract
R&D	Research and Development
RMB	Renminbi, Currency of the People's Republic of China. RMB8.31 = US$1
ROR	Rate of Return
SACI	State Administration of the Coal Industry
SAPCI	State Administration for Petroleum and Chemical Industries
SCADA	System Control and Data Acquisition
SDPC	State Development Planning Commission
SEPA	State Environmental Protection Administration
SETC	State Economic and Trade Commission
SINOCHEM	China National Chemicals Import and Export Corporation
SINOPEC	China National Petroleum and Chemicals Corporation
SNG	Substitute Natural Gas
SO_2	Sulphur Dioxide
SOE	State-Owned Enterprise
SPC	State Planning Commission, former name of the SDPC
SPCC	State Power Corporation of China
T&D	Transmission & Distribution
tcm	Trillion Cubic Metres
TEPCO	Tokyo Electric Power Corporation
TNK	Russia's Tyumen Oil Co.
TOD	Time of Day
TOP	Take-or-Pay
TPA	Third Party Access
TPES	Total Primary Energy Supply
TSP	Total Suspended Particulates
TWh	Terra Watt-hour
UNCTAD	United Nations Conference on Trade and Development
UNIPEC	China United Petroleum Company
VAT	Value Added Tax
WB	World Bank
WEO	World Energy Outlook
WEP	West East Pipeline
WTO	World Trade Organisation

GLOSSARY OF TERMS

City gate
Point at which a local gas distribution company takes delivery of gas; physical interface between transmission and local distribution systems.

Capacity charge
Price asked for reservation of particular capacity of the gas infrastructure (e.g. pipeline/s, storage) independent of whether used or not.

Captive gas consumer
A consumer who does not have any choice but to use gas or a consumer who, once connected to gas, has little or no ability to switch to another fuel in view of the high costs that such a switch would imply.

Commodity charge
Price asked for the gas volume as such (for gas as a commodity; distinct from other charged costs such as customer charge, capacity charge or charge for other services).

Cost-plus pricing: an approach that prices a commodity or service based on its costs of production regardless of market conditions. For natural gas, it involves the following:
Well-head (regulated) price
+ Pipeline mark-up cost
+ Costs of load management
+ Local distribution mark-up cost
= Sales price to consumer.

Downstream
Activities related to natural gas that involve distribution and sales to gas users, including direct sales to large users such as power plants.

Economics of scale
The reduction in unit cost when producing larger quantities of one product.

Feedstock
Natural gas used as essential component of a chemical product (e.g. fertilizer).

Interruptible service
Gas sales and transportation service that is offered at rebate to compensate for the right to interrupt the delivery of gas or the service according to previously agreed criteria (e.g. cold weather, or at discretion, but only for a total limited time.)

Load factor
Ratio that the average demand or throughput over a year bears to the maximum demand for a given time period (e.g. one day, one hour, etc) or to the capacity expressed as a percentage.

Market replacement value
The price of gas at which the end-user incurs the same costs when using gas instead of alternative fuels such as coal and oil products, taking into account differences in heat value, efficiency and costs for the appliances or equipment necessary to use the energy, plus eventually different valuation of resulting pollution, if provided by a market mechanism.

Midstream
Activities related to natural gas that involve transmission and underground storage.

Natural monopoly
An economic activity in which the production of a particular good or service by a single producer results in lower unit cost than by multiple producers. It usually involves an industry with a decreasing marginal cost of production and high entry barriers, so that the incumbent producer can monopolise the market.

Net-back pricing
An approach that calculates the market value of natural gas at any point upstream of the final consumers in the gas chain, by deducting from the average market replacement value the costs (for distribution, load and quality management and transportation) necessary between the point in the gas chain considered and the final consumers. The net-back price at the well-head, for example, is calculated as the average of all customers using the following formula:

Market replacement value
– Distributor charges for distribution and load management
– Pipeline transportation charge
= Net-back price at the well-head.

Off-take
Actual amount of gas taken from the transmission or distribution system.

Opportunity cost
The net economic loss (forgone earnings minus forgone costs) by choosing one opportunity over another.

Peak storage
Gas storage designed/used to supplement normal gas supply during short periods of extremely high demand.

Proven Reserves
Those reserves that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions.

Rent
The difference between the market replacement value and a lower price of gas paid by the consumer (consumer rent) or the difference between the price paid to the producer and the cost of production incurred by the producer (producer rent).

Take-or-Pay (TOP)
A contractual commitment on the part of a buyer to take a minimum volume of gas or pay for it if not taken, usually over a 12-month period.

Third-party access (TPA)
The obligation to the owner of an essential facility to offer access to third parties to idle capacity of such facility under non-discriminatory conditions.

Two-tier pricing system
An older pricing system introduced in China during the early reform period that prices a commodity in two different ways: a state-controlled price for a given volume that is usually set by quota, and a free market place (usually higher than the controlled price) for the volume above the quota.

Upstream
Activities related to natural gas that involve exploration, development, production, gathering and purification.

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