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NATURAL GAS END-USE PRICES

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FOREWORD

I am pleased to present the final report of the study, APEC Energy Pricing Practices: Natural Gas End-Use Prices. This report is the second phase output of the study on energy pricing practices in the region, succeeding the initial report published in March 2000, titled APEC Energy Pricing Practices: Implications for Energy Efficiency, Environment and Supply Infrastructure. Although the phase one report covered all member economies and all forms of energy, due to limitations in the availability of data and information, there arose some demand for a more detailed look at some more specific issues.

This study attempts to overview and evaluate natural gas end-use pricing practices in the APEC region with particular attention being paid to subsidy and cross-subsidy issues, in an effort to add useful information to the discussion of subsidy reform within the changing environment of world energy markets. Different methods and objectives of (cross-) subsidisation exist across industries and economies depending on industry characteristics, development needs, and consideration of other social policy concerns. Best pricing practices emphasise efficiency with pricing theory implying that the existence of (cross-) subsidies means that prices are distorted in some way. However best pricing practices do not seem to exclude subsidisation either, if it is agreed that it leads to the best outcome in a second-best world.

This report is published by APERC as an independent study and does not necessarily represent the views or policies of the APEC Energy Working Group or individual member economies.

I would like to thank all those who have been involved in this study including the staff of the Centre, both research and administrative, the experts who have assisted us through our workshops, conferences and other deliberations, and many others who have supplied information and insights. I hope this report will not only contribute to ongoing discussions about the issues herein but also be used as guidance to understanding and policy formulation in other areas of energy markets in addition to natural gas.

Keiichi Yokobori

President

Asia Pacific Energy Research Centre

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List of Abbreviations

ACE	ASEAN Centre for Energy
AEEMTRC	ASEAN-European Community Energy Management Training and Research Centre
APEC	Asia-Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
ASEAN	Association of Southeast Asian Nations
Bcf	Billion cubic feet
Bcfd	Billion cubic feet per day
BCM	Billion Cubic Metres
BTU	British Thermal Unit
CCGT	Combined Cycle Gas Turbine
COLR	Carrier of Last Resort
COS	Cost of Service
EDMC	Energy Data and Modelling Center (Japan)
EGEDA	Expert Group on Energy Data and Analysis
EIA	Energy Information Administration (USA)
EWG	Energy Working Group (APEC)
FCC	Federal Communications Commission (USA)
FDC	Fully Distributed Cost
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GW	Gigawatt (109 Watts)
GWh	Gigawatt hour (109 Watt hours)
IEA	International Energy Agency
IEEJ	Institute of Energy Economics, Japan
IMF	International Monetary Fund
IPP	Independent power producer
IRR	Internal Rate of Return
kcal	Kilo calories
KEPCO	Korea Electric Power Corporation
KOGAS	Korea Gas Corporation
kW	Kilowatt (= 1,000 watts)
kWh	Kilowatt hour (= 1,000 watt hours)
ktoe	Kilo tonnes of oil equivalent
LDC	Local Distribution Company
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LRMC	Long Run Marginal Cost
METI	Ministry of Economy, Trade and Industry (Japan)
MFV	Modified Fixed Variable
MITI	Ministry of International Trade and Industry (Japan)
MOCIE	Ministry of Commerce, Industry and Energy (Japan)
MOFE	Ministry of Finance and Economy (Korea)
Mtoe	Million tonnes of oil equivalent
MW	Megawatt (=10^6 Watt)
MWh	Megawatt hour (=10^6 Watt hours)
NEB	National Energy Board (Canada)
NGCC	Natural Gas Combined Cycle
NRCan	Natural Resources Canada
OECD	Organisation for Economic Co-operation and Development
PPP	Purchasing Power Parity
POSCO	Pohang Steel Company (Korea)

PPP	Purchasing Power Parity
PTT	Petroleum Authority of Thailand
SFV	Straight Fixed Variable
SOLR	Supplier of Last Resort
SRMC	Short Run Marginal Cost
Tcf	Trillion cubic feet
TPEC	Total Primary Energy Consumption
TPES	Total Primary Energy Supply
TWh	Terawatt hour (=10^{12} watt hours)
UN	United Nations
US(A)	United States (of America)
USDOE	United States Department of Energy
USO	Universal Service Obligation

EXECUTIVE SUMMARY

BACKGROUND

There exists a large body of literature on utility pricing virtually all of which is concerned with efficient and equitable pricing practices for utility services. In particular, while there have been many discussions about cross-subsidies that may exist among diverse energy services, consumers and consumer groups, few, at best, empirical or quantitative analyses have been undertaken. The reason seems to lie in that those analyses require a huge amount of comprehensive and detailed micro-data. Even under circumstances where detailed accounting data are available, there exists another problem of linking the accounting information to the economic concepts of efficiency and equity. This fact may explain why some economies have adopted the strategy of introducing competition, unbundling of services, and divestment of companies without objective and accurate analysis and evidence of the existence and magnitude of cross-subsidies.

Although the absence of cross-subsidisation is neither a necessary nor a sufficient condition in itself for welfare maximisation, it is known that its existence may induce an inefficient entry of new suppliers into the market. Or, put differently, the absence of cross-subsidisation will ensure that provision of services makes all consumers as well off as they can be. However, the possibility of welfare being maximised in the presence of cross-subsidies should not be precluded even when their existence and magnitude cannot be verified, because notions of fairness and equity can change the opportunity set for the government or the regulator.

In 2000, APERC published a report titled "APEC Energy Pricing Practices: Implications for Energy Efficiency, Environment and Supply Infrastructure." It overviews the theory of energy pricing and the existing pricing practices for coal, petroleum products, natural gas and electricity across all twenty-one APEC member economies. Limitations in the availability of data and relevant pricing information had been a significant constraint during the study and, therefore, although all economies had been covered, the level of detail varied. Also, as the report had covered a wide range of issues, there arose some desire to look in more detail into some more specific issues.

The natural gas industry is one of the markets in which reforms and restructuring are actively taking place. Also, diverse pricing policies and regulations are applied over the APEC region and, particularly, subsidies and cross-subsidies are believed to exist in some sectors of the market to enhance market development or for other social policy objectives. However, the issue of the merits of subsidisation or cross-subsidisation has been controversial in terms of the notions of both efficiency and equity. Therefore, it was considered useful to investigate the natural gas pricing practices in the APEC member economies in the context of market reforms and subsidisation.

OBJECTIVES, SCOPE, AND METHODOLOGY

This study surveys the theory and practices on end-use natural gas pricing in the APEC region, with attention being paid especially to the issues of subsidies and cross-subsidies. The specific objectives and scope of this study are:

- To overview the pricing practices for natural gas end-uses in selected APEC member economies;

- To overview the literature on cost-based multi-product utility pricing, such as fully-distributed cost pricing, subsidy-free pricing and cost-axiomatic pricing;

- To evaluate pricing practices of selected member economies against theory;
- To derive implications for natural gas pricing policy; and
- To collect and analyse data and information on natural gas pricing practices.

In addition to an ordinary literature survey, APERC conducted a survey of natural gas pricing practices through APEC EGEDA contacts. The following issues, augmented by responses to the questionnaire based on them received from the EGEDA contacts, serve as focal points in performing the study.

- Market drivers in a historical perspective;
- Deregulation, competition, cream-skimming and consumer protection;
- Universal service obligation;
- Government's willingness to mobilise price policy to resolve issues;
- Government's awareness of and willingness to remedy problems, if any, related to (cross-)subsidies; and
- Methods of gas pricing other than the traditional cost-plus method.

MAJOR FINDINGS

Although the FDC pricing method is the most commonly used one and subsidy-free under certain restrictions, it has shortcomings in that, amongst others, there is no place for efficiency in this method. That is, the method makes it possible to recover total costs but does not take marginal costs or price elasticities into account. Similarly, while the cost-axiomatic approach may be useful to incorporate some notions of equity or fairness in gas prices, it is difficult to link the efficiency notion to this method.

A price is (cross-)subsidy-free if the revenue from the service under this price is greater than or equal to its incremental cost and less than or equal to its stand-alone cost. However, it is possible, perhaps usual, that an individual consumer thinks of himself as subsidising others whereas the price he pays is, in fact, subsidy-free. This implies that the real issue concerning subsidies and cross-subsidies may be more focused on fairness than on efficiency.

The single most important point about fairness notions is that they are quite often incompatible with each other and there may be no feasible price solution that satisfies all the fairness criteria. Theory says that the constraints of achieving fairness reduce the feasible set of tariffs and may leave no scope for surplus maximisation.

The social welfare function and constraints perceived by policy makers or regulators may be different across economies. Regulators may be regarded as attempting to make an optimal choice based on their perceptions of social welfare functions and constraints in a second-best or third-best world. The constraints include short- and long-run development paths, efficiency, equity (fairness), and other social objectives.

Some explicit subsidy mechanisms have been found in use. Examples are the Chilean rural electrification program and the U.S. Federal government's auctioning of subsidy funds for universal services in telecommunications. It is conceivable that such mechanisms could be adopted in natural gas markets. The broad approach is one of government procurement of universal services. Issues and problems concerning the incentives of service providers in the bidding remain. One issue is how to optimally design the auction mechanism.

Another recent argument about the cross-subsidy problem is that traditional cross-subsidies should be retained within the scope of universal services if any subsidy is to be provided at all. This shows that many policy makers and economists still acknowledge the necessity of subsidisation for certain services and consumer groups.

As natural gas markets become more liberalised and deregulated, the scope for subsidies and cross-subsidies is reduced. However, while it is still true that there are less cross-subsidies within a liberalised sub-sector, cross-subsidies remain possible between liberalised and non-liberalised sub-sectors.

Within the market reforms framework, a small consumer tends to be defined as one who may need protection by the regulator from monopoly power while large consumers are those who have supply options within or outside a specific energy market. One notable trend is that the scope of small consumers is becoming narrower as market reforms progress.

There are some regional or economy-specific features concerning subsidies and cross-subsidies in natural gas end-use.

- In North America, albeit on an empirical basis, deregulation may have eliminated or reduced cross-subsidies in transportation rate structures and in retail distribution markets. At the same time, due to efficiency gains in commodity gas markets, overall inflation-adjusted prices for all classes of consumers have fallen. Regulatory changes over the last two decades have helped to encourage more transparent and cost reflective transportation rates. Retail markets are slowly being opened up to competition with the potential to reduce or remove cross-subsidies.

- In Japan, the recently amended Gas Utilities Industry Law provides further rate options for customers and allows city gas companies to supply beyond their franchise areas. MITI's (recently changed to METI) rate approval system has been abolished and changed to a notification system if city gas companies lower gas rates and change supply conditions that would benefit customers. To facilitate network access by third parties, the creation of fair, cost reflective access tariffs is under consideration.

- In Korea, efforts have been made to reduce cross-subsidies from the power generation sector to city gas consumers by, for example, further deregulation and changes to price structures. However, there remains a clear cross-subsidy to gas for air-conditioning of commercial buildings from other types of end-uses - the final price level has been below the gas cost for some time - to improve the consumption pattern of gas and air quality. Many agree that the initial subsidy policy has contributed to the fast penetration of natural gas into non-electricity uses and reduced the unit supply cost more rapidly than would otherwise have been the case.

- In Southeast Asian economies, governments support strategic industries such as steel and fertiliser manufacturing with price subsidies for inputs such as gas. There are ongoing efforts to improve the effectiveness of such policies. For example, the Indonesian government is reallocating diesel fuel subsidies to natural gas for electricity generation.

- In Oceania, although difficult to separately identify, historically there have been cross-subsidies in the sector. Due partly to competitive pressures, these have either been completely eliminated or are being phased out. New Zealand has a small but well-developed reticulated gas market. Deregulation and market reforms in the 1990s have seen the gradual removal of cross-subsidies that have existed with household prices having risen faster than prices for industry in the last decade. In Australia, cross-subsidies that existed prior to the mid-1990s have been eliminated or reduced for similar reasons. The fragmented state of the industry and the lack of basin-to-basin competition mean that there are currently wide disparities in prices between regions. These variations are likely to disappear as new interstate pipelines are completed and Australia achieves a more integrated gas transmission system.

CONCLUSIONS

In summary, different ways and objectives of subsidisation exist across industries and nations within the APEC region according to industry characteristics, economic development imperatives and consideration of other social policy concerns. After all, any policy, including subsidisation, is decided through a political process reflecting a variety of measurable and non-measurable benefits and costs. If this statement is accepted, there remains the issue of so-called best practice. Certainly, best pricing practices emphasise efficient pricing and the existence of (cross-)subsidies means that prices are distorted. However best pricing practice does not seem to exclude subsidisation if the term "best practice" means prices that would give a "best" result in a second-best world.

The appropriateness of subsidisation as a policy instrument depends on what the policymaker tries to achieve with it. If there are positive externalities, subsidies may serve to internalise them, with the optimal design of the subsidy mechanism and financing scheme left to be the focus of policy discussion - financing with general tax revenue, financing with funds raised within the energy sector or within the gas sector, etc. On the other hand, if the policy goal were to achieve certain spill over effects that could be more effectively achieved through incomes policy, an energy subsidisation policy would be the wrong choice of instrument. This is where, for instance, the targeting problem arises, since subsidisation involves income redistribution as well as price distortions between subsidising and subsidised individuals.

Subsidies or cross-subsidies are not a bad policy instrument per se, so that the issue is subsidy reform, not subsidy removal.

CHAPTER 1

INTRODUCTION

Normally, large gas consumers have more power than small consumers in bargaining with suppliers, not only are their consumption volumes larger, their load factors are, in general, also higher. These factors are known to tend to lower gas supply costs not only to the larger consumers themselves but also to the smaller consumers in the long run in the absence of cross-subsidies from the former to the latter.

There exists a large body of literature on utility pricing virtually all of which is concerned with efficient and equitable pricing practices for utility services. In particular, while there have been many discussions about cross-subsidies that may exist among diverse energy services, consumers and consumer groups, few, at best, empirical or quantitative analyses have been undertaken to date. The reason seems to lie in that those analyses require a huge amount of comprehensive and detailed micro-data. Even under the circumstances where detailed accounting data are available, there rises another problem of linking the accounting information to the economic concepts of efficiency and equity. This fact may explain why some economies have adopted the strategy of introducing competition, unbundling of services, and divestment of companies without objective and accurate evidence of the existence and magnitude of cross-subsidies.

Although cross-subsidisation is neither a necessary nor a sufficient condition in itself for welfare maximisation, it is known that its existence may induce an inefficient entry of new suppliers into the market. Or, put differently, the absence of cross-subsidisation will ensure that production and sale of services makes all consumers as well off as they would otherwise be. However, the possibility of welfare being maximised in the presence of cross-subsidies should not be precluded even when their existence and magnitude cannot be verified, because notions of fairness and equity can change the opportunity set for the government or, more generally, the regulator.

In 2000, APERC published a report titled “APEC Energy Pricing Practices: Implications for Energy Efficiency, Environment and Supply Infrastructure.” It overviews the theory of energy pricing and the existing pricing practices for coal, petroleum products, natural gas and electricity across all twenty-one APEC member economies. Limitations in the availability of data and relevant pricing information had been a significant constraint during the study and, therefore, although all economies had been covered, the level of detail varied. Also, as the report had covered a wide range of issues, there arose some demand to look in more detail into some more specific issues after its publication.

The natural gas industry is one of the markets in which reforms and restructuring are actively taking place. Also, diverse pricing policies and regulations are applied over the APEC region and, particularly, subsidies and cross-subsidies are believed to exist in some sectors of the market to enhance market development or for other social policy objectives. However, the issue of desirability of subsidisation or cross-subsidisation has been controversial in terms of the notions of both efficiency and equity. Therefore, it would be a valuable exercise to look into the natural gas pricing practices in the APEC member economies in the context of market reforms and subsidisation. On these grounds, this study surveys the theory and practices for end-use natural gas pricing in the APEC region, with attention being paid especially to the issues of subsidies and cross-subsidies. It is hoped that this report may contribute to the decision-making processes of energy price policies in the APEC region and the on-going discussions on energy subsidy reform around the world.

The structure of this report is follows. An overview of the issues concerned with natural gas prices and cost allocation practices is presented in the next chapter. Chapter 3 discusses some theoretical and practical aspects of natural gas end-use pricing based on a survey of recent literature on the subject. Chapter 4 reviews the existing practices in sub-regions, with more detailed reviews of a few selected economies set aside for Chapter 5. The last chapter concludes the report with some policy implications.

PROJECT OBJECTIVES AND SCOPE

The objectives of this study are:

- To overview the pricing practices for natural gas end-uses in the APEC member economies;
- To overview the literature on cost-based multi-product utility pricing, such as fully-distributed cost pricing, subsidy-free pricing and cost-axiomatic pricing;
- To evaluate pricing practices of selected member economies against theory;
- To derive implications for natural gas pricing policy; and
- To collect and analyse data and information on natural gas pricing practices.

BASIC QUESTIONS

The following issues, augmented by the responses received from a questionnaire based on them from EGEDA contacts, serve as focal points in performing the study.

- Historical perspective - market drivers
- Deregulation, competition, cream-skimming and consumer protection
- Universal service obligation - lifeline, elderly, handicapped, etc.
- Government's willingness to mobilise price policy to resolve issues
- Government's awareness of and willingness to remedy problems, if any, related to (cross-) subsidies
- Methods of gas pricing other than traditional cost-plus method

CHAPTER 2

OVERVIEW OF THE ISSUES

It is known that large-volume natural gas consumers such as electricity generators and large industrial and commercial consumers play a major role in forming the market base for natural gas. An essential feature of the large-volume consumers is not only that their gas consumption volume is large but also that their consumption variation, either seasonal or daily, is relatively small, resulting in the advantage of less need for costly construction of complex distribution networks in early stages of natural gas utilisation. In addition, it is believed that the large volume of natural gas consumption by large-volume consumers can reduce the burden of common costs that small consumers have to bear and, therefore, can contribute to the expansion of natural gas use to the latter group of consumers. Based on these beliefs, many economies have adopted the strategy of introducing natural gas firstly to the large-volume consumers and then expanding supply to small consumers.

Recently, energy market reforms and industry restructuring have been progressing in the direction of introducing competition among suppliers in a sector in which traditionally a state-owned or private monopoly supplier has supplied energy service with an obligation to supply in exchange for a monopoly franchise. One important factor that has made this possible is technological development. For example, the high-efficiency CCGT technology has facilitated competition in power generation. Also, regulatory reform and information technology have facilitated competition by making it possible for competitors to have third party access to natural gas pipelines or electricity grids which have been owned and operated by vertically integrated monopoly utility companies without hampering system security and at fair access prices. However, the most important driving force toward more competition has been the belief that effective competition between suppliers will realise more efficient energy use and resource allocation. In short, the governance mode in energy markets is shifting from one of mimicking the market to one of the market mechanism itself.

In general, the segment of the natural gas market to become the first and main target of reform into which supply competition, including self-supply or bypass, was to be introduced was the group of large-volume consumers such as power generators and large industrial and commercial users. This is hardly surprising as their consumption volumes are larger and their load factors are, in general, higher than that of small consumers, and, accordingly, the unit cost of supplying the former is lower than that for the latter. This is the more competitive and dynamic segment of the market as suppliers would be keen not to lose this profitable portion of their market. Also, large-volume consumers find it is easier to switch fuels in response to price and also find it was easier to change gas suppliers under gas-to-gas competition. These factors confer bargaining power to the large-volume consumers and make them the main target segment of the market to which supply competition has been introduced.

However, arguments have been raised against market reforms mainly from the side of the traditional vertically integrated utilities, which are the target of restructuring. Amongst others, one argument is that if regulatory oversight of utilities, including pricing schemes for energy services, could adequately replicate the market and induce sufficient investment in supply facilities, we would not have to pay a huge amount of transition costs in the process of moving toward a more competitive market structure. Then, what are the sufficient, and perhaps necessary, conditions for regulatory oversight to adequately replicate the market? The most important but most difficult one would be that the regulator should have enough information on the demand and cost conditions of suppliers. Instead of attempting to collect the costly information, regulators rather have tended to choose to let the market find the 'right' price.

Almost every economy relies on various subsidising policies for goods and services of basic needs with subsidies in kind on the one hand and subsidies through government-manipulated structures and levels of price on the other. One of the most important positive effects that have been expected from market reforms and industry restructuring is that subsidies and cross-subsidies would be removed or at least reduced. Many economies have employed price subsidies on natural gas uses arguably in consideration of the universal service characteristic of city gas[1] service. In the natural gas supply industry, there exist a variety of common assets that contribute to the supply of diverse services and the price structure of those services is prone to cross-subsidisation by the very nature of those assets. Subsidies and cross-subsidies distort the price structure, tending to result not only in inefficient energy demand and supply but also inefficient resource allocation throughout the economy.

It is safe to say that removal of subsidies or cross-subsidies on natural gas uses or energy service in general will enhance efficient resource allocation within the sector in question, while the theory says that efficiency improvement in a sub-sector of an economy does not guarantee efficiency improvement in the whole economy.[2] Some argue that the removal of subsidies on fossil energy will increase their prices to an efficient level and can contribute to the reduction of greenhouse gas emissions from reduced fossil energy consumption. However, it is known that a subsidy-free price structure does not necessarily mean welfare is maximised under that price structure, but it only ensures that provision of each service under that price structure is Pareto superior to non-provision. In addition, subsidy-free prices may well not exist at all, and, furthermore, even where they exist, it becomes even more difficult to determine the linkage between welfare maximisation and cross-subsidisation once equity issues come into the picture. Inefficient entry and no market equilibrium might result if entry barriers are lifted without knowledge of supply costs and consumer preferences. However, many economists believe that 'the policy errors induced by the presence of legal entry barriers tend to be more detrimental than the errors made by their absence' [Mitchell and Vogelsang, 1991].

More often than not, the removal of subsidies and cross-subsidies in the energy sector is required to be included in energy sector reform plans in order for an economy to obtain foreign capital for the construction of energy supply infrastructure. As a result, the issue of subsidy and cross-subsidy brings about a trade-off to host economies of access to those funds. That is, on the one hand, a host economy may want to expand the market base for natural gas and enhance the quality of life of its people by adopting the strategy of subsidisation and cross-subsidisation. The increased market base and higher living standard will enhance the investment environment for private and/or foreign capital in the natural gas sector in the long run. On the other hand, however, in the short- to medium-term, an economy in need of capital has to level the playing field between domestic capital and foreign capital by, for example, removing subsidies and cross-subsidies.

The issues of cross-subsidisation and sustainability of a natural monopoly situation may be seen from the perspective of the adverse selection problem. That is, in more general terms, the issue involves an attribute of 'Gresham's Law', which says, “Bad money drives out good.” In this context, the services, consumers or consumer groups that provide subsidies to others can be regarded as good money and the subsidised bad money. In terms of pure theory, the equilibrium outcome will be either a closure of the market or two separate markets, the self-selection outcome. Applied to our discussion, a circumstance where cross-subsidies are present under legal entry barriers may be seen as a case of adverse selection whether or not subsidy-free prices exist in the market. One note of caution, as mentioned above, the relationship between subsidy-free prices and welfare maximisation is not strong.

In an industry that is characterised by huge amounts of fixed capital to set up supply facilities and by the difficulty of identifying service-specific or consumer-specific common costs, there exist risks of incurring additional costs for duplicated supply facilities. Therefore, it may be concluded that the governments which have introduced competition in some segments of their natural gas market, for example, industrial and commercial end-users, may be seen to have taken the view that: large-volume consumers might have subsidised small consumers; large-volume consumers believe they subsidise small consumers; large-volume consumers have bargaining power with suppliers; and supply competition for large-volume consumers will remove cross-subsidies from them to small consumers.

During the period between 1985 and 1999, a period that is expected to be enough to show some evidence of the effects of restructuring moves such as FERC Orders 436 and 636, changes in natural gas prices show a wide variation across end-users (see Table 1). The gas price for electric utilities shows the largest decline at 49 percent followed by industrial on-system[3] consumers with a 46 percent decrease. Considering that the industrial and commercial consumers shown in the table are on-system consumers, it is likely that there were even larger price decreases for off-system[4] industrial and commercial consumers.

Table 1 Natural Gas Prices in the United States

	Nominal Price		Real Price (1999 US$)		Percent Change (Real)
	1985	1999	1985	1999	
Wellhead	2.51	2.07	3.56	2.07	-42
Import	3.17	2.29	4.5	2.29	-49
City gate	3.75	3.11	5.32	3.11	-42
Residential	6.12	6.6	8.69	6.6	-24
Industrial	3.95	3.04	5.61	3.04	-46
Electric Utilities	3.55	2.56	5.04	2.56	-49

Source: Massey 2000

It seems that the figures in the table fit quite well with our discussion. However, it should be noted that, in addition to the wellhead price reduction, both a reallocation of common costs among consumer groups and efficiency improvement in transmission and distribution are at work in the differences in price changes. It should also be noted that, in addition to the competition in the wellhead and transportation services, there was a big shift in the rule of allocating fixed costs from the Modified Fixed Variable (MFV) method to the Straight Fixed Variable (SFV) method, which resulted in shifts of more fixed costs to small residential and commercial consumers.

There arises a problem here that it is possible that the small captive customers are subsidising large-volume customers, on-system and off-system alike, as a result of the combined forces of the changed rule of fixed cost allocation, competition for the off-system customers and the threat of on-system customers going off-system. In order not to see this kind of situation occur, the regulator cannot but continue price regulation taking into account the whole natural gas market.

Alternatives are being offered for circumstances where subsidies are inescapable for the so-called universal service obligation (USO) even after competition has been introduced.[5] The first alternative is that suppliers may share the subsidy for the universal service with the pre-competition price structure being maintained. Or, so as to avoid price distortions, the government may raise funds for the price subsidy out of general taxation revenue. Third, the government may rely on social safety nets rather than price subsidies. However, all these alternatives involve some deadweight loss to the economy and it is not clear whether this inefficiency will be smaller or larger than the inefficiency accruing from the price subsidy itself.

Some recent studies look more closely at the cross-subsidy and universal service issues, but still few issues have been resolved and the arguments are mixed. For example, Palmer argues that there was a significant amount of cross-subsidy in the telecommunications service in the New England area from business customers to residential customers [Palmer, 1992]. Bradley, Colvin and Panzar deal with a methodology for testing for cross-subsidies and subsidy-free rate-making for the U.S. Postal Service with micro accounting data [Bradley, Colvin and Panzar, 1999]. Crew and Kleindorfer argue for the need to design and implement a mechanism for the optimal scope of the universal service obligation and reserved monopoly (franchise) area for an incumbent utility if certain services are to remain as universal services and to be supplied by the incumbent [Crew and Kleindorfer, 1998]. Sorana suggests that auctions for explicit subsidies are better in a wide range of circumstances than traditional ways of subsidisation [Sorana, 2000].

Apart from subsidy-free prices not being a sufficient condition for welfare maximisation from the theoretical perspective, the methodology for their calculation has not been developed well enough to allow for proving their existence or magnitude. The reason for this lies in the complexity of the concept and the formidable data requirements for its estimation. Simplistically speaking, as long as the prices of services provided by a multi-product monopoly fall between their incremental cost and stand-alone cost, they are said to be subsidy-free. Therefore, a price structure that may appear to include cross-subsidies may in fact not contain any cross-subsidy elements. Moreover, up to now, most concepts related to cross-subsidies are static ones, which means that the discussion would become even more intractable if we introduce time elements into the discussion such as time-varying prices like peak and off-peak prices and changing industry structure over time.

APERC initiated this study by asking the following questions to each APEC member economy. These questions and the answers that were received were borne in mind in preparing this report. The answers have provided some general information on market players, price-setting mechanisms, types of natural gas prices, policy objectives taken into consideration in the price-setting process, and some measures of infrastructure development needs.

- What are the governing laws, rules, and regulations for the natural gas industry? And, what and how do they mainly rule?
- Who are the major players and what are their roles in the natural gas industry?
- Which consumers are defined, if any, as large/small consumers?
- What are the major concerns in the process of gas rate-making?
- What are the components of end-use natural gas price and how are they reflected in it?
- How often is the end-user price revised and how is the revision process triggered?
- Are there rate differentials based on, for example, season, time of day and consumer type?
- Is there any difference in gas price-setting mechanism between city gas and power generation?
- Is there a special mechanism for end-users to contribute toward financing of gas supply facilities?
- Are there any incentive regulation or performance-based ratemaking elements? Or, is there such a scheme under development? If so, what are the main reasons for adopting this option?

- Could you provide some measurements that can show the degree of the gas supply infrastructure development in your economy?

- Could you provide the utilisation rates of the gas pipelines in your country on the basis of, say, gas throughput (volume or energy) per unit length of the pipeline and pipe diameter?

- What is the most important policy concern in the downstream natural gas market in your economy today? And, what measures is your government mobilising to resolve it?

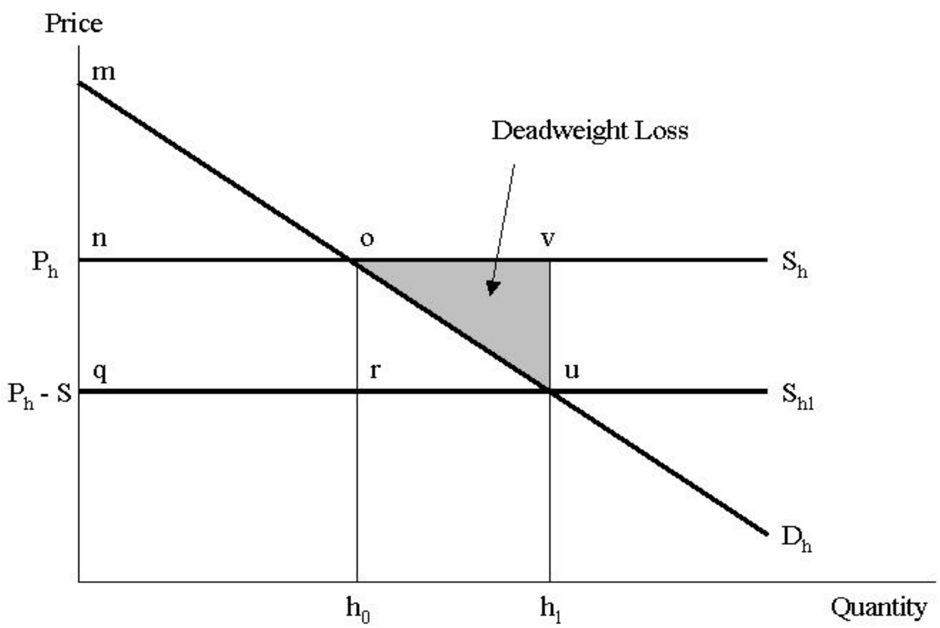
- How does your government approach the cross-subsidisation issues?

CHAPTER 3

THEORY AND PRACTICE OF PRICE SUBSIDISATION

DEADWEIGHT LOSS OF SUBSIDY

Figure 1 Deadweight Loss of a Subsidy



A subsidy or cross-subsidy is just a negative tax. And, as such, it is associated with excess burden or deadweight loss, which can be illustrated by Figure 1.

For simplicity, assume that the demand for natural gas for residential heating is the straight line D_h. Also assume that supply is horizontal at price P_h, which is equal to the social marginal cost of supplying gas for residential heating. In the absence of price intervention, gas demand in equilibrium will be h_0. Now suppose that regulation stipulates that the residential customers be subsidised by S per unit of gas. Then the new gas price faced by the residential customers is P_h - S and the implied supply curve is S_{h1}. The new market equilibrium occurs at the demand volume of h_1. That is, the subsidy S increases the gas demand from h_0 to h_1.

If the purpose of the subsidy was to increase the gas demand, the subsidy is a success, as we can find some cases in developing economies where governments employ subsidy policies to develop a domestic gas market. But, if the goal of the subsidy policy is to maximize social welfare, can it be called a success? Without the subsidy, consumer surplus was the area *mno*. After the subsidy is introduced, consumer surplus is the area mqu. The benefit to the residential customers is the increase in their surplus, area nouq. But the cost of the subsidy is the volume of gas consumed, qu, times the subsidy per unit, nq, or, equivalently, the rectangle $nvuq$. This shows that the cost of the subsidy is greater than the benefit even when the administrative cost of raising the subsidy fund is ignored. Therefore, there is an excess burden equal to the difference between the cost and benefit of the subsidy, which is shown as the shaded area ovu.

The reason that the subsidy is inefficient can be further explained. Any point on the demand curve measures how much people value that particular level of consumption. Although people do derive utility from consuming more gas to the right of h_1, its value is less than P_h, the social marginal cost of supplying the gas (infra-marginal or non-Pareto-relevant at the margin). Consumers now demand gas that is valued at less than its cost, thereby incurring inefficiency.

If the fund for the subsidy is raised in a distortionary way, then the social cost of the fund is even greater than the rectangle excluding the administrative costs. This is the thrust of arguments about the inefficiency of subsidies or cross-subsidies. Here, the distortionary way of raising the subsidy fund refers to raising it by charging other products or consumers higher prices. When a consumer is charged a higher price than the social marginal cost of supply, then his consumption behaviour will change (be distorted) accordingly and there will occur a similar, but opposite in direction, excess burden or deadweight loss. Depending on the relative price elasticities of subsidising and subsidised consumers or products/services involved, the deadweight loss associated with subsidy collection may very well exceed any welfare gain.

In the telecommunications services market, the single most important argument for providing a subscribership subsidy has been the network externalities. Individual A's having access to the telecommunications network increases the utility of an existing subscriber, individual B's welfare by expanding the scope of the telecommunications capacity for individual B. In a similar manner, individuals' access to the natural gas network may arguably increase the welfare of others in that the increased welfare of the former may increase that of the latter, especially if the environmental premium and the convenience in consumption of natural gas are considered. In other words, an individual's 'access' to a natural gas network incurs network externalities, that is, it has a public good aspect.

Barnett and Kaserman point out a few pitfalls concerning a subsidy to network access with a simple theoretical model [Barnett and Kaserman, 1998]. Firstly, the mere existence of a network externality, even a very substantial one, does not automatically justify a subscribership subsidy. The externality must be Pareto-relevant (present at the margin), if the subsidy is to increase welfare. Secondly, although in a strict first-best sense, a uniform subsidy across all customers or even a uniform subsidy within a well-defined subset of customers can only be guaranteed to increase social welfare in the unlikely event where the marginal value to existing customers of these potential subsidy recipients connecting to the network is the same across all recipients. Thirdly, a subscribership subsidy is welfare-improving only if the incremental welfare gains from correcting market-determined outcomes for the presence of the (Pareto-relevant) externality exceed the incremental welfare loss caused by raising the necessary funds.

Some implications for the real world are as follows. Attention must be paid to the level of penetration and the magnitude of externalities created by a subsidy. The higher the penetration rate, the smaller the externalities will a subsidy create and, accordingly, the more inefficient the subscribership subsidy will be. In the context of city gas market, the low price elasticity of residential (and small commercial) consumers along with a comparatively high price elasticity of demand of large-volume consumers suggests that any potential welfare gains obtainable from cross-subsidies may be more than offset by welfare losses caused by the collection of the subsidy funds, if a major portion of these funds are raised from the large-volume consumers.

A regulated, profit-maximising utility may have an incentive to expand business into marginally attractive markets so long as its captive market is counted on to cover the costs, including the return on capital for the added investment in the expansion. The regulated utility may seek to compete with other companies in outside markets on the condition that it is protected from competition in its captive market and that its regulated price will cover total revenue requirements, including the hidden subsidies necessary to make it profitable to expand operations. In other words, it is possible that the utility's captive customers subsidise other customers in its competitive markets. This sort of inefficiency has been referred to as the Type II Averch-Johnson effect and is closely related to the difficulties of clear allocation of common fixed costs in the utility industries.

In addition to the inefficient expansion of business and capital investment, the subsidies from captive customers to competitive ones may induce the utility to practice predatory pricing in the competitive market, which prevents competition from developing in the competitive fringe. In addition to inefficiencies resulting from less competition in the latter, these kinds of cross-subsidies raise wealth transfer or income redistribution problems. It can be a serious social policy issue especially if the competitive market for the company is mainly for the larger consumers or the rich whereas the captive market is for the poor or for the general public.

COMMON COST AND ECONOMIES OF SCALE AND SCOPE [6]

Natural monopoly is characterised by technology and associated with economies of scale and scope. If costs can be saved by only one firm producing a product (single product) or by combining the production of two or more products (multiple product), and if they cannot be exhausted by the scope of the market, the market is one of natural monopoly. The economies arise from spreading fixed costs over output volume or from sharing common costs between products. For example, in the telephone services, there are common costs where the local loop serves both the local calls and long-distance calls. In the natural gas market, trunk lines serve residential consumers as well as industrial consumers and power generators. The demands are identifiably different, but the costs of serving them are shared.

> A cost function C(x) exhibits economies of scale if
>
> *C(lx) < lC(x)* for all *l > 1, x ¹ 0* (strictly decreasing ray average costs), and
>
> it exhibits economies of scope if
>
> $C(ax + (1\text{-}a)y) \leq aC(x) + (1\text{-}a)C(y)$ for $0 \leq a \leq 1$ (transray convex),
>
> where $x(p) = (x_1(p), \ldots, x_n(p))$ is an n-product joint demand function, p is the price vector, and x and y are arbitrary non-negative output vectors.

COST ALLOCATION AND ISSUES OF CROSS-SUBSIDY

This section presents a few approaches to the allocation of costs, each of which is different from Ramsey pricing. As is well known, common costs are also covered in Ramsey pricing. However, the cost concept is the marginal cost of providing each service. Although each service contributes to the common costs so as to make the service provider break even, the services do the job only collectively in setting the level of contribution.

In utility rate-making where a utility has monopoly power and the regulator approves a tariff, standard practice has been that the costs of the utility firm are broken down into common costs and attributable costs, and each service is assigned a part of the common costs. The approaches of rate-making in this way are generally called cost-based pricing. Three approaches are discussed, namely, fully distributed cost pricing, cost axiomatic pricing, and subsidy-free pricing.

Although there is a close relationship between the so-called subsidy-free prices and economic efficiency, economic efficiency was not the primary concern of each of the pricing approaches. Rather, certain notions of fairness or equity have been the primary concern for regulators. And the notions of fairness are usually reflected in the level and structure of rates through political processes. This fact may be able to explain the apparent alienation of observed utility tariffs from the ones that would have been observed if only efficiency criteria had been considered in the rate-making. Indeed, many economists and practitioners have been saying that utility rate-making is rather art than science.

Also, there seems to be a strong fairness perception among customers of a utility, which may well be the number one cause of some confusion with the concept of cross-subsidies. Specifically, a group of customers tend to regard themselves as cross-subsidising others when they find themselves paying a relatively higher price than other groups of customers, while the tariffs are subsidy-free. In this regards, we will look briefly at a few common notions of fairness before proceeding.

NOTIONS OF FAIRNESS

Notions of fairness are a very important aspect of utility rate design but are not always mutually compatible.[7] They can be viewed as constraints in tariff space that reduces the set of feasible tariffs from which to choose. For instance, if notions of fairness give rise to subsidies or cross-subsidies, the resulting prices may be far from those resulting solely from efficiency considerations. Some of the fairness notions are briefly described below.

- *Economic right.* This notion of fairness is demand-related, for example, an economic right to a particular service such as residential telephones. This implies access to the service for everybody (universal service). Thus, the right normally takes the form of a constraint. To specify such a constraint requires definition of the scope of the right in terms of services (for example, access to a telephone line for every household) and the identification of the sources of finance (for example, tax revenues or cross-subsidies).

- *Status quo fairness*. A presumption of fairness that rests on present arrangements may be called status quo fairness. The status quo can refer to producers and/or to consumers. Referring to both groups, status quo fairness would only allow tariff changes that are Pareto improvements. Again, fairness takes the form of a constraint, in this case a constraint on existing utility levels.

- *Cost causality*. An element of fairness follows cost causality (inclusive of subsidy-free, anonymously equitable, and other fairness concepts). Fully distributed-cost pricing is in this sense perceived as fair in that it prevents non-users of a service from paying for it. Cost causality is important not only because cross-subsidisation may be unfair but also because cross-subsidisation invites inefficient entry or bypass of the subsidising services (cream-skimming).[9] This type of fairness generates constraints on prices with respect to cost concepts.

- *Due process and equal opportunity*. An aspect of fairness arises in the overall service process and the opportunity it affords. Free entry into a market is perceived as fair, for example, in terms of offering equal opportunity to all potential entrants. The resulting criteria for desirable tariffs strongly overlap with the notions of fairness above. This is understandable since a necessary condition for entry (including entry by bypass of incumbent suppliers by consumers themselves) is the ability to supply a subset of consumers at costs that are below their outlay under the incumbent's tariff.

If the notions are incompatible sometimes, then the question is how to strike a balance not only between surplus (not welfare) maximisation and fairness but also between incompatible notions of fairness. Incompatibility between different notions of fairness may mean that there is no feasible solution satisfying all fairness criteria. The constraint of achieving fairness work in the direction of reducing the feasible set of tariffs and may leave no room for maximisation, because it leads to a unique feasible outcome as in the case of cost-axiomatic pricing.

However, it may also be argued that, in practice, the regulator or government has its own welfare function that encompasses both the notions of fairness and efficiency, and the utility tariffs that are found in everyday life have been produced through the complex process of balancing those criteria. Moreover, if we go up one more level, while it may sound rather conceptual, the regulator may be seen to make an efficient choice among diverse combinations of notions affecting welfare.

COST-BASED PRICING[8]

FULLY DISTRIBUTED-COST PRICING

Fully distributed-cost (FDC) pricing consists of a whole set of approaches of common cost allocation. Once this allocation is done, prices are set so that the revenue from each service just covers its fully distributed cost. The distinguishing feature of FDC pricing is that common costs are allocated without much attention paid to the efficiency consequences of cost allocation criteria.

The three ways of allocating common costs that have been employed most frequently are the Relative Output Method (ROM), the Gross Revenue Method (GRM), and the Attributable Cost Method (ACM). Under the ROM, common costs are allocated on the basis of the share of each service in the total output of the firm. The GRM allocates common costs according to each service's share in total revenue. Common costs are allocated by the share of each service in the total attributable costs under the ACM. If we denote the share of common costs to be allocated to a service i by f_i, then the fully distributed cost of a service i can be expressed as the following:

FDCi = (attributable cost of i) + f_i x (common cost).

The approaches are distinguished by the way of obtaining fi in the following formulae,

- $f_i = Q_i/(Q_1+\ldots+Q_n)$ under ROM,
- f_i = (revenue from service i)/(total revenue) under GRM, and
- f_i = (attributable cost of i)/(total attributable cost) under ACM,

where Q_i, $i = 1, 2, \ldots, n$, is the output level of service i.

It is known that when the firm's profit is regulated to be zero, the GRM and the ACM are equivalent.

One of the important uses of FDC methods is to test for the existence of cross-subsidies. In a case before the Federal Communications Commission (FCC) between AT&T and non-Bell companies concerning private line services in the 1960s and 1970s, the latter argued that AT&T private line rates were below cost. AT&T argued that its rates covered its incremental costs, and, therefore, they were compensatory. In response to the argument by competitors that the FDC method was appropriate, AT&T undertook a study based on various FDC methods. Although the study results varied depending on the method used, they showed that substantially higher rates of return were applied to the two services which faced no competition, Message Toll Service and Wide Area Telecommunications Service, than such services as private lines, in which AT&T faced competition.

The results were quite supportive of the possibility that there was cross-subsidisation across AT&T services from the non-competitive services to the services in the competitive market. The FCC viewed that FDC methods provided an appropriate method to test for the existence of cross-subsidies, reflecting the concern about whether consumers of monopolistically provided services subsidise other consumers in competitive markets.

However, there are many shortcomings of FDC as well. First, different FDC methods are arbitrary and can lead to widely different results as proved in the case described above. Second, there is no place for economic efficiency in the FDC pricing method. It merely tries to recover total costs without proper consideration of marginal costs. Related to this argument is the absence of price elasticity in the process of rate-making except, for example, revenue forecasting. Lastly, economists have argued that the FDC pricing method cannot be used for the purpose of a cross-subsidy test. A cross-subsidy test based on FDC method deals with a service as it is operated or has been operated. There is no such incremental comparison as that of a service user with the service and in the absence of the service.

COST-AXIOMATIC PRICING (AXIOMATIC APPROACH TO COST-SHARING PRICES)

The cost-axiomatic approach to pricing starts with a set of axioms about the relationship between price and cost that is regarded as intuitively desirable. Then, features of prices are deduced which are consistent with those axioms. The precise axioms that one adopts are different in part by the inclusion of fixed costs in the cost function. Discussed below are six axioms that are commonly considered under the circumstances where the cost function is not assumed to represent the long-run efficient technology for a given level of output and there are fixed costs present. For the sake of simplicity of the discussion, mathematical expressions will not be used.

Axiom 1: Cost Sharing. Total revenue equals total cost.

Axiom 2: Rescaling. Changes in units of measurement should result in prices in such a way that they have no effects on revenues.

Axiom 3: Consistency. Services with the same effect on cost have the same price.

Axiom 4: Positivity. A service that affects costs must have a positive price.

Axiom 5: Additivity. If a service can be split up in the cost function into separate services, then the sum of prices for the individual services has to equal the price for the combined service.

Axiom 6: Correlation. Assignment of common costs to services has to correlate with relative variable costs.

Axiom 1 refers to the requirement that the company break even across all services. It is obvious that the FDC pricing method fulfils this requirement. Axiom 2 is neutral in regard of efficiency and equity. Axiom 3 implies that all services with the same marginal cost should be priced the same. It refers to a situation where cost depends on total output of some group of services. For example, the capacity cost of a gas utility depends on total peak demand, which is the sum of all the demands of (all customer classes) in the peak period. According to the axiom, since a one unit increase of output for a group of customers has the same effect on total output as a unit increase of output for another group of customers, and, hence, the same effect on cost, the two groups of customers pay the same price for the peak demand. It is evident that this consistency axiom means that the prices derived from the six axioms have no special claim to efficiency. Services with the same marginal cost are paid the same price even when their price elasticities of demand are different. The more precise meaning of Axiom 4 is that if a cost function C_1 commands higher marginal costs than another cost function C_2, then a reasonable cost allocation mechanism should assign C_1 higher prices than C_2. Axioms 5 and 6 state that if total variable costs can be written as the sum of additive components, then each component should be assigned an additive share of the common costs which is correlated with the relative size of the (additive) variable cost components. Loosely speaking, it means that services that are relatively costly in the short run (high variable cost) will account for a relatively large share of long-run cost, too. Hence, they should get a relatively large share of the common (fixed) costs.

It is known that the only pricing mechanism that is consistent with the six axioms is the so-called modified Aumann-Shapley price. The Aumann-Shapley price of a service is sort of an averaged marginal cost of the service. The modified Aumann-Shapley price modifies this pricing concept so that the prices of services recover total costs. In a special case where variable costs are additively separable among services and there are no special set-up costs to a particular service, the only pricing mechanism that satisfies the six axioms is the ACM method of FDC pricing approach. While these conditions are quite restrictive, this form of cost function is widely used for practical purposes. Although, as discussed above, the FDC pricing approach does not offer a test for cross-subsidy, the FDC methods are themselves subsidy-free under the restrictions given above. Also, the fact that the ACM method results in the modified Aumann-Shapley price when the cost function is additively separable provides an axiomatic foundation to the ACM method and may be regarded as not too arbitrary.

There are charges against this pricing approach, too. In short, economists argue that the axioms are not economically motivated. Following Mitchell and Vogelsang, not all of them are consistent with economic efficiency [Mitchell and Vogelsang, 1991]. For example, axioms 3 and 6 may be inconsistent with the economic efficiency requirement in that consumers may value services differently while they have the same effect on cost and that any assignment of common costs may lead to inefficient choices while they may be subsidy-free. In other words, the prices resulting from this approach are not responsive to demand.

The axioms may prove more useful to provide equity and fairness perspectives for any pricing mechanism. All six axioms seem to be compatible with fairness defined by due process and equal opportunity. Treatment of fairness defined in terms of cost causality is arguable, since common costs simply cannot be causally assigned. One scepticism about cost causality being employed as a fairness criterion for common cost allocation argues that it may be a very one-sided concept of fairness, because it leaves out of consideration the different amounts of consumer surplus that different buyers receive. Fairness defined by the status quo may or may not be compatible with the axioms; this compatibility actually depends on the specific status quo. Fairness defined as an economic right to a service potentially conflicts with most of the axioms, in particular with Axioms 1, 3, 4, and 6. Especially Axiom 4 is not necessarily compatible with Rawlsian fairness.

SUBSIDY-FREE PRICING (GAME THEORETIC APPROACH TO COST ALLOCATION)

Charging different customers different prices for apparently the same service does not always imply the presence of cross-subsidies or even price discrimination (air travel may be considered an example). Suppose a firm producing only two products, A and B. Product A cross-subsidises product B if and only if the revenue from A is greater than its stand-alone cost and the revenue from B is less than its incremental cost. The stand-alone cost of A is the cost that the firm would incur producing A but not B. The incremental cost of B is the additional cost of B that the firm would incur if it produced B given that A is already being produced in its production line. It may be useful to look at an example of subsidy-free pricing scheme for understanding the concept of cross-subsidies and associated incentives of players (See Box).

AN EXAMPLE: SUBSIDY-FREE PRICES

Suppose a diesel generator, costing $1,000 a year to lease, supplies electricity to two firms, firm 1 and firm 2. Also suppose that the only other cost of supplying electricity is the cost of diesel fuel consumed by the generator and that firm 1 uses electricity whose production consumes $500 of diesel a year, and firm 2 $200 a year. If firm 1 pays only $600 a year, is it being cross-subsidised by firm 2, which, if total costs are to be covered, must pay $1,100? No. Although firm 1 appears to be getting a good deal, it is pays more than its incremental cost (its fuel cost), while firm2 pays less than its stand-alone cost (the generator plus its fuel). The arrangement may even be in firm 2's interest: charging firm 1 a higher price might cause it to stop buying any electricity; perhaps, for example, it has the opportunity to buy enough natural gas to meet its needs for only a little more than $600. If firm 1 did switch to natural gas, firm 2 would have to pay all the costs of the generator as well as of its fuel--$1,200 rather than $1,100 it paid before.

Source: Irwin, T., "Price Structures, Cross-subsidies, and Competition in Infrastructure", Public Policy for the Private Sector, Note No. 107, The World Bank, February 1997.

Economists, many of whom were employed by Bell Laboratories, began to formulate a rigorous theory of cross-subsidy in the early 1970s. Based on the theory of cooperative games, they attempted to define carefully what is meant by cross-subsidy, to compute prices which do not cross-subsidise or are subsidy-free and to provide tests for whether or not given prices are subsidy-free.

Suppose a situation within the framework of a cooperative game where there could be potential gains from diverse coalitions of *N* players. For example, if technology is such that average cost decreases with the number of consumers, then there would appear to be potential gains from forming a large coalition of consumers to be served by a single utility. The crucial question here is whether there exists sets of prices for membership which keep members from defecting from the grand coalition of *N* players to form other, smaller coalitions. Where this is possible, the theory describes how to find sets of prices that keep the coalition stable. Usually there will exist more than one such set of prices. The collection of all sets of prices that keep the grand coalition of *N* players from fragmenting is referred to as the core. Since the pioneering work by Faulhaber, economists have tended to equate subsidy-free prices with prices that are in the core [Faulhaber, 1975]. That is, a set of prices contains cross-subsidies if some players can improve their situation by defecting and forming a smaller coalition.

The simplest kind of game to look at is one in which the *N* players can be thought of as consumers attempting to be served at minimum cost. Thus, off-peak service would be considered a player, etc. For simplicity, assume that demands are completely price-inelastic, so that outputs for each player are fixed. Suppose that there are *N* players and a cost function *C(S)* that gives the minimum cost of serving a coalition *S*, where *S* is a sub-coalition that can be formed out of the *N*-player (grand) coalition. All possible sub-coalitions *S* are continually considering whether or not to defect form the grand coalition and be served by a specialty firm using the same technology as the monopolist. Faulhaber defined *C(S)* as the stand-alone cost of coalition *S*. Each possible sub-coalition has its own stand-alone cost. To keep each coalition *S* in the grand coalition *N*, the sub-coalition *S* cannot be charged more than its stand-alone cost.

Denote by r_i, $i \in S$, the price (or revenue) paid by (collected from) any member of the sub-coalition *S* to belong to the grand coalition. Thus, to prevent *S* from defecting for each possible sub-coalition *S* which can be formed out of the grand coalition *N*. In addition, the monopolist serving the *N* players must break even:

When both of these sets of constraints are met, then no sub-coalition $_S$ will want to break away from the grand coalition and be served at a lower cost. In the language of game theory, when a set of prices r_1, r_2, …, r_N satisfies the constraints (1) and (2), we say that they are in the core of the cost game.

There is another interpretation of these conditions. Consider a subset *S*, which is paying less than or equal to its stand-alone cost:

$$\sum_{i \in S} r_i \leq C(S) \qquad \text{......................................} \quad (1)$$

Denote all other consumers by *N-S*; they, too, must pay no more than their stand-alone cost *C(N-S)*. Incorporate this into the regulated firm's breakeven constraint::

implying that

$$\sum_{i \in N} r_i = C(N) \qquad \text{......................................} \quad (2)$$

$$\sum_{i \in S} r_i \leq C(S)$$

$$\sum_{i \in S} r_i = \sum_{i \in N-S} r_i + \sum_{i \in S} r_i = C(N)$$

$$\sum_{i \in S} r_i \geq C(N) - C(N-S).$$

Thus, all groups in *S* must bring in at least their incremental cost, a condition that must hold for all such possible sub-coalitions. Thus, when the monopolist is assumed to break even, prices $_{ri}$ which are subsidy-free (that is, in the core of the cost game) have the following two equivalent features:

(i) No group of consumers pay more than its stand-alone cost.

(ii) Each group of consumers pays at least its incremental cost.

In short, if the price(s) charged to consumers of certain service(s) raises revenue to the firm that falls between the stand-alone costs and incremental costs of the service(s), it (they) is (are) subsidy-free. In this cost game, players are contemplating forming coalitions so as to reduce the cost of producing their demands. Up to here the benefit side of the market has been ignored in the discussion. If the solution to the cost game results in prices that exceed the benefits that players derive from consuming their outputs, then they will defect. To take account of this benefit constraint, the following set of conditions are added which must be satisfied:

$$r_i \le b_i, \quad i = 1, 2, \ldots, N, \qquad (3)$$

where *bi* is the benefit that player *i* derives from consuming *Qi*. When these constraints are met, in addition to the core constraints (1) and (2) for the cost game, then a solution is found to what is known as the benefit game.

At this point, it is instructive to compare the results of FDC pricing to the cross-subsidy conditions. The FDC pricing rules all come down to the following form:

$$R_i = AC_i + f_i F, \quad f_i < 1, \qquad (4)$$

where f_i is the fraction of fixed costs, *F*, paid by service *i* and *Ri* is the revenue to be paid by service i. To compare this with the core constraints, suppose for a moment that demands are all fixed. It is clear that FDC prices are all in the core of the cost game:

$$\sum_{i \in S} R_i = \sum_{i \in S} (AC_i + f_i F) \le \sum_{i \in S} AC_i + F, \quad \text{for } S \text{ £ } N \qquad (5)$$

$$\sum_{i \in N} (R_i - AC_i) - F = 0. \qquad (6)$$

Therefore, when the cost function takes the separable form with a fixed cost, the FDC method results in subsidy-free prices.

The distinction between FDC prices based on test period data and demand-compatible FDC prices is relevant here. By holding quantities fixed in the cost game it is as if test period quantities and costs were used. As pointed out above, when these prices are actually put into effect, quantities will change from their test period levels. When they do, the breakeven constraint will be violated and prices will not be subsidy-free. If demand-compatible FDC prices are arrived at, they will satisfy the subsidy-free constraints of the cost game and will also not violate the benefit constraints.

This discussion confirms a central contention of economists: that FDC prices are not tests for cross-subsidies. Since any FDC method is subsidy-free, no single one can be used as a test for cross-subsidies. On the other hand, the extensive critical discussion by economists about FDC prices seems to have missed the other point made in this discussion, which is also germane; that when the firm's joint cost function is additively separable, the FDC prices are themselves subsidy-free. Therefore, they are not entirely devoid of merit.

It may be pointed out briefly that a connection exists between absence of cross-subsidy and economic efficiency. To be subsidy-free, revenues for each possible grouping of services must at least equal the incremental cost of that grouping. If this condition was violated, not only would cross-subsidies exist, but also the discussion of economic efficiency above indicates going to a subsidy-free set of prices could increase that total surplus.

SUBSIDY-FREE PRICES AND SUSTAINABILITY

A set of prices by a multi-product monopoly is called subsidy-free (or free of cross-subsidies) if revenues at these prices cover total costs and if no subset of services produced by the monopoly at these prices could be produced at costs lower than the revenues generated for this subset by these prices [Faulhaber, 1975].

In the absence of diseconomies of scope, there are two alternative tests for determining whether prices are subsidy-free. Both tests require the consideration of stand-alone costs. It is very hard to calculate stand-alone costs empirically, because, given economies of scope and cross-subsidies, no separate subset of commodities is ever likely to be produced.

Two complications are involved in the incremental cost test. The first is that while individual products may pass the test, combinations of such products may not pass the test at the same time. The reason is that joint or common costs of several products are not incremental costs of each individual product but they are part of the incremental costs of combinations of the products viewed together. The second complication arises from demand interdependencies between products. For instance, the revenue raised from an additional product may reduce the revenue of another product due to substitutability of demands.

The first (Faulhaber's) definition of subsidy-free prices is entirely in terms of *products*, not in terms of *customers* consuming those products. Due to cost complementarities, a customer buying more than one product could still be subsidising other customers. Therefore, a stronger notion involving consumption bundles rather than individual products is needed.

A price vector p represents supportable prices for a quantity vector x if no consumption bundle

$x^* \leq x$ can be produced at costs $C(x^*) < p¢x$. A cost function $C(x)$ is supportable at x if such support prices exist.

Even if there is no subsidy-free price structure in terms of individual products, there may still exist subsidy-free prices in terms of bundles of products demanded by consumers. Such prices are called *consumer subsidy-free*.

Consumer subsidy-free prices are those prices for which total revenues at demanded quantities cover total costs and no coalition of consumers could produce their demanded quantities at costs lower than what they pay under these prices. Faulhaber and Levinson show that any cost-covering price structure is consumer subsidy-free if all consumers have the same demand patterns (except for a common scale factor), which is a rather restrictive condition [Faulhaber and Levinson, 1981]. Knowledge of individual demand functions is required to test for consumer subsidy-free prices.

A supportable price structure is subsidy-free, and no customer or customer group will subsidise any other customer or customer group. However, the quantity x needs to be compatible with market demand:

anonymously equitable prices are support prices satisfying $x = D(p)$ (Faulhaber and Levinson, 1981).

A support price need not be anonymously equitable. A (upper hemi-) continuous market demand (correspondence) and a supportable cost function are sufficient conditions for the existence of an anonymously equitable price vector. Anonymous equity is the strongest concept so far, since anonymous equity implies that prices are subsidy-free, are consumer subsidy-free, and are support prices. The stand-alone cost test and the incremental cost test are each a sufficient condition for testing anonymous equity if products are substitutes, and are necessary conditions if services are complements [Mitchell and Vogelsang, 1991].

OPTIMAL UNIVERSAL SERVICE OBLIGATION

Ubiquity of service and uniform pricing are two primary attributes of a universal service [Crew and Kleindorfer, 1998]. The requirement for a utility of ubiquity of delivery combined with the uniformity of price, regardless of costs, are the basic ingredients that constitute the universal service obligation (USO). Traditionally, the USO has been seen as the requirement to offer standard service to all at affordable rates, often coupled with various constraints on the quality of service.

Crew and Kleindorfer (1998) suggest that the USO could be considered as prescriptions on services which take one of four forms: ubiquity alone; ubiquity with uniform price but no quality restrictions; ubiquity with uniform quality restrictions but no uniform price restrictions; and ubiquity with uniform price and some quality restrictions. Although these different types of universal services have different cost-benefit consequences, they share the common feature that they require certain cross-subsidies from lower-cost services to higher-cost services. While it is not a tradition in the gas supply industry to charge a uniform price, the argument about universal service obligation and cost differences across products or services and their implications on cross-subsidies between consumers is the same, at least qualitatively, between the postal and the gas supply industries.

The emphasis in the traditional definition of the USO is on the level of cross-subsidy from low-cost products or services to high-cost products or services implied by uniform pricing if the incumbent service provider is to break even. With the advent of market reforms and competition, both from other gas suppliers and from other types of fuels, maintaining the USO becomes increasingly difficult as cross-subsidies are put under pressure by competitors who can potentially target specific customer segments with customised service offerings (cream-skimming). This trend suggests generalising the traditional concept of USO to better address the implicit tradeoffs between the extent of the USO, the supporting sources of guaranteed revenue, and economic efficiency.

Entry has the potential to improve both static and dynamic efficiency in that service or cost innovations occur when entrants produce a given product or service more economically or with better service quality attributes than the incumbent(s). By contrast, under a USO, entry may not provide any of these promised efficiency gains. Where the entrant has higher costs than the incumbent, there are clear efficiency losses from the increased costs. Even where an entrant has lower costs than the incumbent, the revenue of the incumbent is eroded and the viability of the USO is threatened. This may be especially true if there are significant cost differences across the services but little price differentiation is applied. The necessary efficiency balance therefore involves a tradeoff between the efficiency benefits of competitive entry and the economic costs of cream-skimming which the USO and heterogeneous costs enable. Achieving the proper balance here requires a mixture of pricing approaches, entry restrictions, and other policy measures targeted at the provision of universal services.

While Crew and Kleindorfer emphasise the transactions cost economy of uniform pricing associated with a USO, the public goods aspect of fulfilling basic needs of, or universal access to, clean and convenient-to-use natural gas by the general public may be placed on the benefit side for our purpose. Their result implies that the more the benefits from the universal service attributes of gas consumption, the larger should be the scope of the USO. And, the larger the size of the fund required to finance the USO, the larger the scope of monopoly of the incumbent in the market. However, the monopoly should be no larger than required to fund the USO. They present a firmer basis on which an efficient USO may be consistent with market liberalisation.

They base their analysis on the assumption that, under the circumstance where competition is feasible and desirable for certain services but other services must remain universal services, an incumbent monopoly should finance the USO with cross-subsidies from the reserved area (monopoly) of its services under a breakeven constraint. On the other hand, other types of financing mechanisms may be utilised in other circumstances. That is, the fund for financing the USO may take the form of explicit subsidies and taxes or whatever may be developed and efficiently implemented. In fact, economists have argued that subsidy schemes should be divorced from the pricing system, with subsidies being made explicit and targeted to those who would not subscribe to the service in question in the absence of a subsidy.

A couple of cases are presented below where an explicit subsidy scheme is adopted through a market mechanism, an auction for subsidy funds.

UNIVERSAL SERVICE AND CONSUMER PROTECTION

To the extent that government sees that there needs to be a universal service, the USO argument may be related to the protection of small consumers in the natural gas market. Examples of universal services include “supplier of last resort” in the gas and electricity markets or “carrier of last resort” in the telecommunications service market.

It is arguable that the consumption of natural gas is a public good; while it is obvious that the gas commodity is not a public good *per se*. However, considering the needs of gas market development in developing economies and the convenience of use and environmental premium of natural gas, the consumption of natural gas certainly entails public good attributes. Especially, the issues of consumer protection have profound implications for equity and fairness as well as efficiency, and they in fact might substantially change the results of a pricing process.

In general, “large consumers” are those who have choices to be supplied other types of fuels than gas or to be supplied gas from more than one supplier so as to have bargaining power in choosing gas suppliers. However, small consumers are not necessarily those consumers who are not large. The term “small consumers” is often used for captive customers of utilities, and, in this sense, the consumers who may need some protection by regulators from the monopoly or market power of utilities.

In Korea, for example, large consumers of local distribution companies are those who consume more than 100,000 m^3 per month.[10] In Japan, on the other hand, they had been those who consumed more than 2,000,000 m^3 per year (average of 166,667 m^3 per month) before, as markets were more liberalised, the scope of large consumers became wider recently.[11] Thus, in Japan, the definition of large consumers was changed to include more of the former smaller consumers in 1999: those who consume more than 1,000,000 m^3 per year are large consumers now.

In the U.K., OFGEM (Office of Gas and Electricity Markets) proposed that there should be a common definition of small customers in the gas and electricity markets to whom certain regulatory safeguards apply upon having identified several problems arising from the different existing definitions in the markets [Office of Gas and Electricity Markets, 2000]. The proposed definition is 'a customer who lives in premises occupied wholly or mainly for domestic purposes'. That is, a small customer is basically a domestic/residential customer for gas and electricity.

OFGEM envisages the types of regulatory protection for the small customers as follows:

- price controls;

- determination of disputes;
- service levels (including codes of practice and standards of performance);
- the duty to supply (including such things as contract terms and marketing); and
- 'supplier of last resort' (SOLR) arrangements.

The U.K. is one of the most advanced economies in the world with respect to energy market reforms. However, it is trying to define small customers as a certain category of customers who need additional protection in the liberalised energy market, which definitely incurs extra costs. For example, in order to satisfy the SOLR obligation, suppliers are required to maintain a bond that would provide funds for the unrecoverable costs faced by the SOLR that would relate only to residential customers.

One of the questions following the arguments about protection of small customers is whether gas and electricity are the kind of utility services that should be supplied universally like some postal services and telecommunications services. However, the state of the world is such that governments often require utilities to provide certain services to all in one way or another, for instance, as long as a potential customer accepts the terms and conditions of the utility service. Thus, if it is agreed that there are certain services that should be or are to be provided at all costs, then the appropriate question will be how to strike a balance between the scope and financing of the potentially high-cost universal services.

SUBSIDY AUCTION

COLR[12] AUCTIONS IN THE U.S. TELECOMMUNICATIONS INDUSTRY

In the U.S., the Telecommunications Act of 1996 mandates universal service subsidies at the federal level on a set of core services.[13] The Act repudiates the traditional way of pursuing the universal service goal by cross-subsidies and the practice of mandated geographic price averaging in favour of the principle of explicit subsidies:

Specific and Predictable Support Mechanism: There should be specific, predictable and sufficient Federal and State mechanisms to preserve and advance universal service.[14]

The Act stipulates the Universal Service Principles on which policies for preservation and advancement of universal service will be based as follows:

1. *Quality and Rates.* Quality service should be available at just, reasonable, and affordable rates.

2. *Access to Advanced Services.* Access to advanced information and telecommunications services should be provided in all regions of the Nation.

3. *Access in Rural and High Cost Areas.* Consumers in all regions of the Nation, including low-income consumers and those in rural, insular, and high cost areas, should have access to telecommunications and information services, including interexchange services and advanced telecommunications and information services, that are reasonably comparable to those services provided in urban areas and that are available at rates that are reasonably comparable to rates charged for similar services in urban areas.[15]

A universal service fund will be raised to finance the universal service subsidies by mandating contributions from providers of interstate telecommunications services. It is expected that the resulting efficiency loss from the increased rates in the interstate markets will be substantial.[16] Although the Federal

Communications Commission (FCC) is interested in the use of auctions to allocate the fund, it has decided to begin with a more traditional policy because of the huge and disaggregated information requirements and the time constraint of implementation of the Act.

Sorana (2000) argues that in a wide range of circumstances auctions are more efficient than traditional subsidy schemes by comparing COLR (carrier of last resort) auctions and ex-post open uniform subsidy (EPOS) schemes, which are competitively neutral. His result shows that COLR auctions can lead to lower subsidies and, more generally, higher welfare levels in a wide range of circumstances.

An EPOS scheme pays the same subsidy for any consumer served in an area under consideration at no more than the regulated price without imposing any other obligation. COLR auctions single out who will receive the subsidy and how much they will receive. The crucial ingredients for the result are the heterogeneity of consumers (in terms of the minimum cost of providing them with the subsidised service) and the regulator's inability to collect sufficiently disaggregated data. The intuition behind the result can be briefly summarised as follows. Consider the smallest service area for which the regulator is able to get reasonable cost data. An EPOS scheme must pay a uniform level of subsidy for all customers in the area, because the regulator normally cannot get more finely disaggregated data than the carriers. The cost of serving these customers, however, generally varies in a manner that is not fully observable by the regulator. An EPOS scheme would have to pay an amount that is sufficiently large to cover the highest-cost customers if these are not to be left out of the universal service coverage. On the other hand, the equilibrium level of subsidies with a COLR auction will depend on some kind of average cost for the area. This will often be less than the minimum cost of serving the most costly customers in the area.

One of the positive attributes of auctions is the possibility of using information that firms have at a much finer level of aggregation than would be attainable by regulators. However, the welfare level here depends on market outcomes that the regulator cannot fully control. That is, the finer information that firms have also has risk implications on the market. The regulator can pay firms directly, but cannot grant them protection from competitors in the market. Also, the regulator knows the price it wants consumers to pay, but does not know how much to pay firms for charging such a price (cost heterogeneity and cost sharing between regulator and customers). Auctions can muster competition “for the market” effectively and reduce the cost of subsidisation, but attempts to achieve strong competition also “in the market” may backfire and result in the loss of competition. In other words, auction designed to stimulate competition among subsidised suppliers may induce collusion among them. This is a classical example of such problems as contractor incentive and collusion involved in the government procurement. Bottom line is that the subsidy mechanism should be designed optimally while maintaining the explicit subsidy and auction scheme.

RURAL ELECTRIFICATION PROGRAMME OF CHILE

In order to increase rural electrification, the Chilean government launched a programme in 1994, which includes subsidies designed to be consistent with the broad principles of energy market reforms such as decentralisation and competition, and a requirement that all stakeholders like consumers, suppliers and the government contribute to the financing of the programme.[17] It is reported that an increase of rural electrification of about 50 percent has been achieved in the first five years of the programme.

The subsidisation mechanism is as follows. The contribution from the central government-the subsidies and the programme management cost-is delivered through a special fund set up to allocate a one-time direct subsidy on a competitive basis to private electricity distribution companies to finance part of their investment costs in rural electrification projects. Companies apply for the subsidy to regional governments, which actually allocate the funds to them according to their evaluation scores of the projects. The central government allocates the subsidy funds to the regions according to two criteria: how much progress a region made in rural electrification in the previous year and how many households still lack electricity. Regional governments contribute their own resources to the programme. Under the programme, subsidies are considered only for projects with a positive social return but a negative private return. A 10 percent real return on investment is allowed over a thirty-year horizon.

Financing responsibility of the project is divided as follows:

- Consumers have to cover the costs of in-house wiring, metering, and coupling to the grid. These costs which amount to about 10 percent of each project are initially paid by the distribution company and repaid by consumers over time. Once the project is in operation, consumers have to pay the regulated tariffs.

- The distribution company is required to invest at least the minimum amount calculated by a formula set by the central government. The company must also operate the project.

- The central government provides a subsidy that is no more than the (negative) net present value of the project, which also has to be smaller than the total investment.

The programme has achieved 76 percent coverage of electric systems in rural areas in 1999, exceeding the 75 percent target set for 2000. The programme is said to have shown that it is possible to design an incentive mechanism that leads to an efficient market outcome at a time when so many developing economies are reforming their energy markets and privatising their state-owned electric utilities. Specifically, the programme has been successful in introducing competition at several levels: between communities, for financing their projects; between distribution companies, for implementation of their projects; and between regions, for the funds provided by the central government.

In 1995 the average state subsidy per dwelling amounted to US$1,080; in 1999 it reached US$1,510. The World Bank's evaluation of this outcome is positive in that it is consistent with the programme's goal of maximising rural electrification within budget constraints which mandates first implementing the projects with the highest impact per unit of investment.

The two cases above explain well that governments, in developed and developing economies alike, continue to face the need for subsidies in the provision of universal services. They show that there can be a welfare advantage of using market mechanisms such as auctions for explicit subsidies, over the traditional cross-subsidies and (approximate) price averaging practices. The explicit subsidy schemes seem to satisfy the notion of fairness, economic right, but to contradict the notions of status quo fairness and cost causality fairness. The auction scheme has been a popular procurement mechanism for diverse goods and services, with its own shortcomings as well as strengths, both in the public and private sectors. But, as is well known, the issue of optimal design has also been an issue of great importance in the field of procurement to avoid, for example, collusion. The schemes of explicit subsidies and cross-subsidies can be seen as a way of procuring universal services from the viewpoint of government. Then, the design of an optimal auction mechanism for subsidies should be the next task for policy makers.

CHAPTER 4

REGIONAL OVERVIEW OF NATURAL GAS PRICING PRACTICES

NORTH AMERICA

OVERVIEW OF NATURAL GAS MARKETS

Since 1985, gas markets in Canada and the United States have undergone a fundamental restructuring. Wholesale gas prices in both economies have been deregulated. Introducing competition has radically changed the way gas is contracted, priced and transported. In the non-competitive aspects of the market, regulatory procedures have been simplified and harmonised, in many cases, resulting in closer integration of the Canada and US gas markets. The market has flourished during this period. To 2000, end use prices have remained relatively stable implying that gas production has kept pace with steady growth in gas demand.

Natural gas is an important energy commodity in both Canada and the United States. Gas consumption in these two economies accounted for 51 percent of demand in the APEC region in 1998 [EDMC, 2001]. Gas is used primarily for space heating in the residential and commercial sectors, as a feedstock for the petrochemicals industry and to produce steam for industrial processes. In recent years with the development of gas turbine and combined-cycle technologies, gas has become more popular for electricity generation purposes.

Natural gas is responsible for about 30 percent of total primary energy consumption in Canada. In 1998 natural gas for end uses and electricity generation amounted to 56,351 ktoe. The industrial sector was the largest consumer at 38 percent, then residential at 25 percent, commercial at 18 percent, non-energy at 9 percent and electricity generation at 10 percent [National Energy Board, 2000a].

In the United States, natural gas made up 23 percent of total primary energy consumption. Consumption for end uses and electricity generation reached 536,043 ktoe in 1999 or 9-10 times higher than Canada. Of this total 42 percent was for industrial uses, 22 percent was for residential, 15 percent was for commercial, 6 percent was for non-energy and 15 percent was for electricity generation [Energy Information Administration, 2000b].

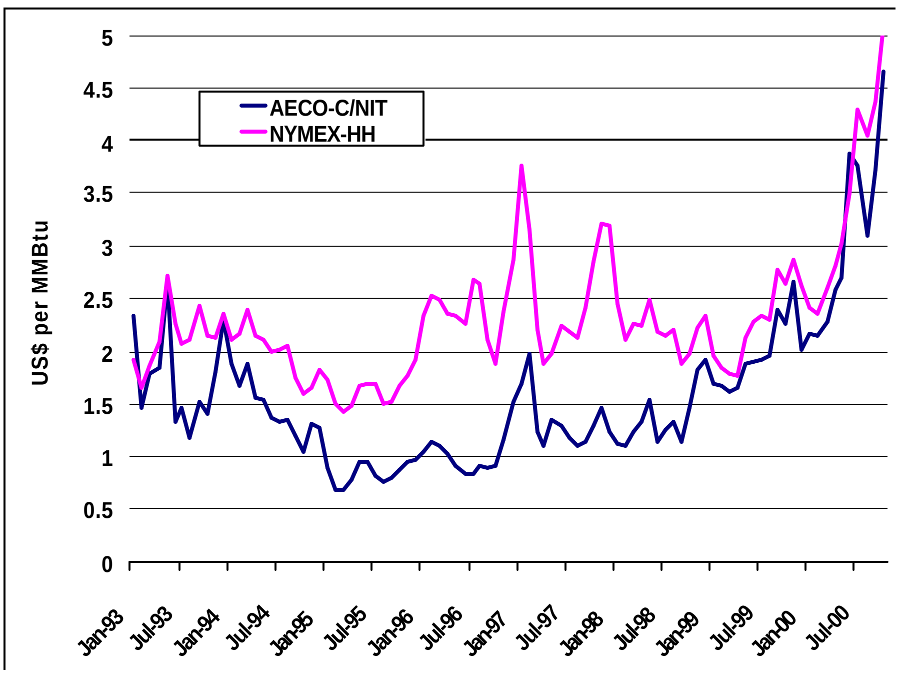
Canada is a large producer of natural gas. Production is located primarily in the Western Canada Sedimentary Basin (WCSB). In late 1999, offshore fields in Nova Scotia began production, diversifying Canada's gas resource base. Canadian gas production totalled 170.3 BCM (6.0 Tcf) in 1999. Approximately 56 percent of this production, 94.8 BCM (3.3 Tcf), was exported to the United States. Reserves were estimated to be 1,606 BCM (56.7 Tcf) [National Energy Board, 2000b]. Domestic gas demand is met entirely through domestic resources.

Gas supply in the United States is spread over several basins. The most important basins are the Gulf coast followed by Andarko, Permian, San Juan and the Rockies production areas. Gas production was about 530 BCM (18.7 Tcf) in 1999. Remaining gas reserves were estimated to be 4,644 BCM (164 Tcf). Net imports, mostly from Canada, totalled 102 BCM (3.6 Tcf) or 16 percent of domestic consumption [Energy Information Administration, 2000d]. Exports from Canada have more than doubled between

1990 and 1999.

The Canadian and US gas markets are linked by an extensive pipeline system. With deregulation, Canadian exports to the United States expanded quickly, filling existing pipelines to the US market and encouraging capacity additions. Since 1990, pipeline capacity from Canada to the US has more than doubled. Pipeline interconnection has resulted in an integrated market where wholesale prices in different markets across the two economies differ by only the cost of transportation. There is essentially one price across all regions. Figure 2 shows 30-day gas prices in AECO-C/NIT, the major pricing hub in Canada, and NYMEX/Henry Hub in the US. Before 1993 and since early 1999 when additional pipeline capacity came into service, prices in the two markets have followed a similar path.

Figure 2 AECO-C/NIT and NYMEX/Henry Hub Gas Prices



Source: Canadian Natural Gas Focus, various issues

During the period 1993 to 1998, Canada's four major pipelines were operating at very high load factors. Due to this shortage of take-away capacity from the WCSB in Canada, gas could not migrate to markets in the United States where supply was tight. As a result of this situation, prices in Alberta became disconnected from prices in other parts of North America. Foothills to the US Midwest and TransCanada PipeLines Ltd (TCPL) brought capacity additions into service in 1998 and the Alliance pipeline to Chicago, adding 1.3 Bcfd (or 500 Bcf per year), began operations in November 2000. These increments have increased take away capacity from the WSCB by about 20 percent and have re-established links between pricing points across North America.

Recently, gas markets in Canada and the United States have tightened. While growth in natural gas demand has been strong for several years, supply additions have not kept pace. Low wellhead prices in 1998 and into 1999 reduced cash flow to the industry and led to a decline in drilling for and development of gas supplies across North America. Wellhead prices recovered in 1999 and drilling activity has since been robust; however, there is a historic lag between developing supplies and bringing them to market, so end use prices are expected to remain high into 2001.

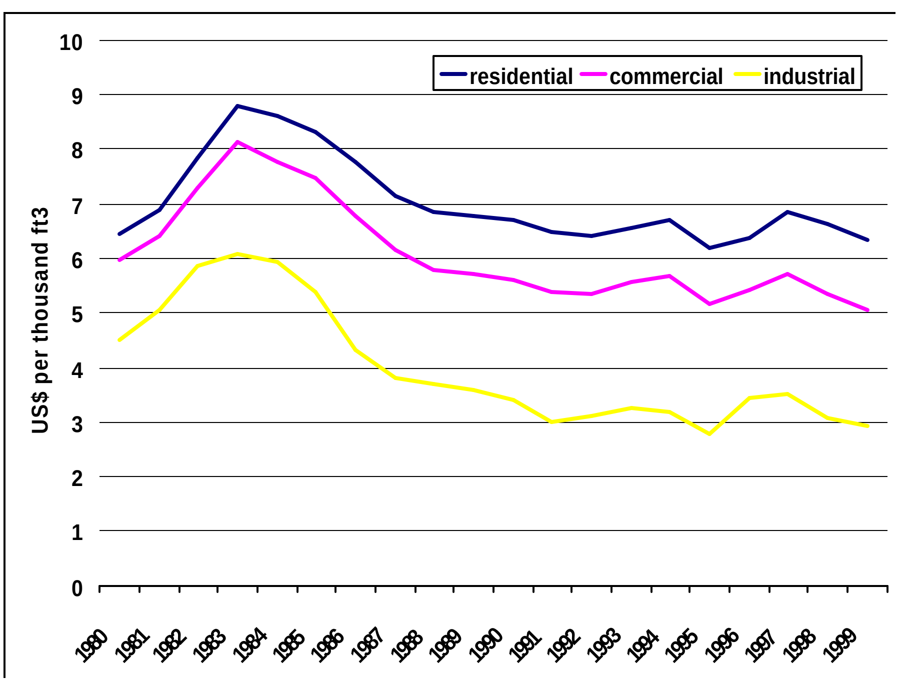
NATURAL GAS PRICING PRACTICES

The basic components which make up an end-use price include: a wellhead or border price for gas, a transportation or transmission cost which gets the gas to the city-gate, storage costs so gas is available to smooth out periods of peak demand, and distribution costs to move gas from the city-gate to the end-use consumer. Previously, all aspects of the price chain from wellhead to end use price were regulated. Market deregulation in Canada and the United States during the last twenty years has opened up many aspects of the gas market to competition. The commodity price of gas is now determined by the market, but certain markets, high-pressure pipeline and retail distribution services, despite some liberalisation, continue to be regulated by governments.

End-use customers are usually divided into three classes: residential, commercial and industrial. Industrial consumers use gas for a variety of purposes including steam production or as a feedstock for petrochemicals. When producing heat or steam for industrial purposes, firms often maintain dual-firing equipment. Demand by these customers is therefore more elastic or price sensitive, because if the cost of gas rises relative to petroleum products, they have the option of switching fuels. The dominant use of gas in the commercial and residential sectors is for space heating. Demand is high and variable in the winter, depending on the weather, and low in the summer. Since most retail customers do not have dual-firing equipment, demand in these sectors is inelastic.

In both the United States and Canada, the introduction of more competition in the mid-1980s resulted in improved efficiency and lower end use prices for all classes of consumers (Figure 3 and Figure 4). In both economies, industrial prices fell at almost double the rate of residential prices because wellhead

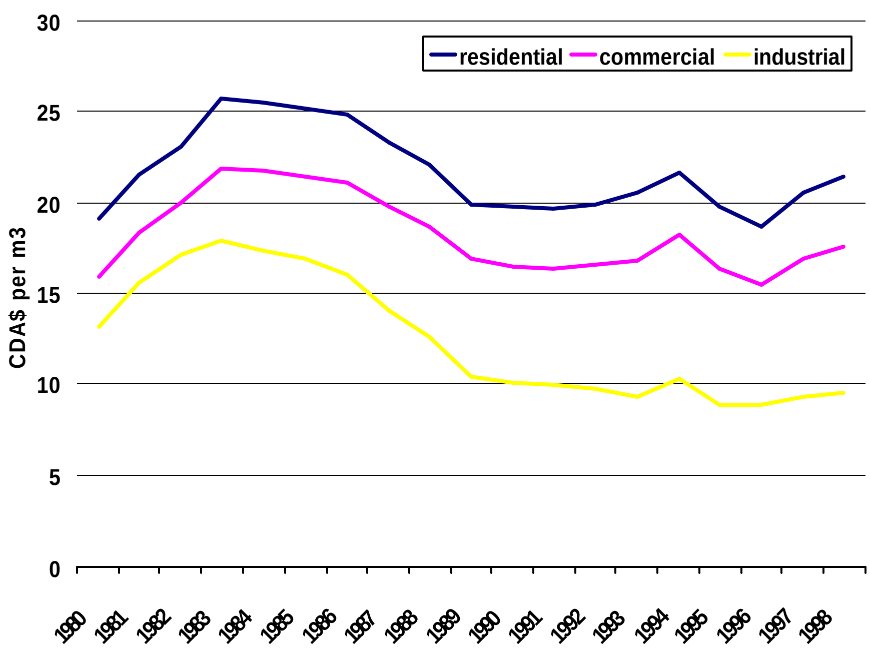
Figure 3 Real End Use Gas Prices in the US (1996=100)



Source: Energy Information Administration, 2000e prices were falling very rapidly in this period, and the commodity cost is a larger proportion of industrial prices than it is of residential prices. After the late-1980s, gas prices stabilised and have remained relatively flat in real terms to 1998. Though official 2000 end use prices are not yet available, spot prices in Figure 2 have spiked upwards and are expected to remain high in the short-term term.

The wholesale market is composed of large end users, gas marketers and LDCs. These customers purchase large volumes of gas directly from producers and contract with pipelines to move their product to delivery points. As witnessed in Figure 3 and Figure 4, these customers pay lower prices than low load factor retail customers. Residential and small commercial users purchase a regulated bundled gas commodity/distribution service from an LDC or buy gas from a marketer and arrange for the LDC to deliver the product.

Figure 4 Real End Use Gas Prices in Canada (1996=100)



Source: Statistics Canada, 2000

To remain competitive, many producers and industrial consumers constantly look for ways to reduce their costs. Since deregulation, wholesale customers have more closely scrutinised regulated tolls for high-pressure gas transmission and they have put increased pressure on pipeline companies and regulators to reduce costs and improve efficiency in pipeline operations.

PIPELINE TARIFFS AND TOLLS

Inter-provincial pipeline in Canada and interstate pipelines in the United States are monopolies subject to regulation by the National Energy Board (NEB) in Canada and the Federal Energy Regulatory Commission (FERC) in the United States. Traditionally, pipeline tolls in both economies have been set using a cost-of-service (COS) approach. The cost-of-service, including operating expenses, depreciation, taxes and a "reasonable" rate of return on capital, is determined for a test year based on an expected level of sales. COS regulation ensures that pipelines are able to recover the cost of capital investments and that there is an adequate supply of pipeline service available to the market. One of the weaknesses of this method of regulation is that pipeline companies have few incentives to innovate and lower the cost of service.

The ideal price structure is one based on marginal cost. In regulating a market characterised by monopoly, economists have argued that the regulator should develop a rate structure which gets as close to marginal cost pricing as possible, yet generates sufficient revenues to recover full costs. To allocate those full costs "fairly," Alfred Kahn proposed that elements of price discrimination be incorporated into rate structures. He defines "good price discrimination" as charging captive customers higher prices so long as they do not exceed the average cost of serving these customers alone. Further, consumers with more elastic demand can be charged lower prices, but these prices should not fall below the marginal cost of service. Under this pricing system, prices are subsidy-free so long as they fall between marginal costs and average costs. Typically, more fixed costs are recovered from those customers who value the service more.

The tolling structure in Canada seems to be achieving these principles of "good price discrimination." The rate design used in Canada is a straight fixed variable (SFV) toll. Firm transportation service is priced using a two-part tariff consisting of a demand charge and a commodity charge. The demand charge or capacity reservation fee recovers the fixed costs of providing capacity and the commodity charge covers the variable costs of transporting gas. Since firm shippers are the only category of customers who pay the demand charge, the fixed costs of capital or the long-term average costs of the pipeline are recovered from this group. These customers, LDCs and some gas marketers, require reliable guaranteed service at all times and they are willing to pay extra for it.

Since pipelines are built to provide service for firm customers, other services available from the pipeline are "secondary" products or spin offs available because of the primary service. Therefore, the economic cost of these "secondary" services is the marginal cost of provision. Other customers, large industrial customers and some gas marketers, have demand needs that are more flexible. This group of customers may subscribe to short-term firm or interruptible service. In Canada, the minimum bid price for these products is set at the variable cost of the service; therefore, this set of supplementary pipeline products also satisfies Kahn's pricing principles. Any profits from secondary services are typically used to lower firm service rates.

In the United States, the MFV toll design methodology that was used in the 1980s, allowed some fixed costs to be recouped from the variable component of the toll. This toll design did not violate Kahn's principles of "good price discrimination," as captive customers were paying less than average cost and more flexible customers were at least covering their marginal costs. High volume customers, however, were paying a larger proportion of these fixed costs than were low volume users. Since customers with high load factors tend to be the most flexible and the most likely to migrate if offered better rates, the MFV was not the most efficient tolling methodology for a competitive market. In 1992, the United States adopted the SFV design which satisfies the criteria for "good price discrimination," yet is more appropriate for a competitive market since flexible customers pay a price which is closer to the incremental cost of service.

In the Canadian market, shippers and pipeline companies have the option of bypassing COS tolls and negotiating revenue and tolling settlements. To date, six negotiated settlements have been approved. The NEB will not approve such a settlement unless all interested parties participated in the negotiations and the settlement is approved by all participants. If these conditions are met, this implies that the tolls determined through negotiated settlements are subsidy-free. If one group of shippers was paying less than the marginal cost for service, someone else would be paying more to compensate, and this party would not approve the rate-settlement proposal. This supposition, of course, assumes that shippers have sufficient information to determine the marginal cost of their service.

The toll design in the COS rate-making process also seems to be subsidy-free. But in a competitive deregulated market where excess capacity is a problem, these rates may not give pipelines enough flexibility to attract new customers. Excess capacity can create financial problems for pipelines since uncontracted firm space means that remaining firm customers pay higher rates, which in turn, may lead to more customers leaving the system. In order to stay competitive, US pipelines are proposing to by-pass this traditional method of rate determination and to negotiate directly with customers. The FERC is cautious for good reason. The regulator's job is to prevent pipeline monopolies from exercising market power by charging captive customers rates that subsidise larger customers with more flexibility. With market-determined rates, even when COS rates are available as a last option, there is a greater potential for cross-subsidisation and "bad price discrimination."

In Canada, excess capacity and new pipe-to-pipe competition have also caused a shake up in the pipeline industry. With all of the new capacity that has come into service recently, TCPL, Canada's largest pipeline is expecting to support excess capacity on its system for many years. In light of these new market conditions, TCPL requested a toll hearing in 2000 and asked the NEB for permission to set the floor price for interruptible service equal to the cost of firm service. It argued that, in an excess capacity environment, interruptible service was practically guaranteed at the floor price and because interruptible customers were ultimately receiving the same service as firm shippers, they should pay their fair share of fixed costs [National Energy Board, 2000c]. This request was denied by the Board, which argued that there was no evidence to imply shippers were substituting interruptible service for firm service or that excess capacity would continue for the long term. The NEB further suggested that TCPL resolve some of these issues with its shipper in its next negotiated settlement. An increase in the floor price of interruptible service, however, was approved.

The problem of excess capacity has created formidable challenges for pipeline companies and regulators in both Canada and the United States. In order to ensure full recovery of fixed costs, pipelines are questioning the established rate structure determined by regulators and are seeking new ways to address this problem.

DEREGULATION IN THE RETAIL MARKET

It should be emphasised that in the Canadian and United States markets there is competition for wholesale gas sales; however, retail gas prices to a large degree, continue to be regulated by provincial/state utility boards. Third-party access to distribution services is available in most markets, but mandatory unbundling of distribution and gas sales services is still rare. Deregulation has taken place more slowly in the retail gas market, which services residential and small commercial clients, than it did the wholesale market. Unlike the wholesale market, which is controlled by one national regulator, retail markets are managed by many local regulators; therefore, since there are more parties involved, the process takes longer. Moreover, the retail market is not very lucrative. Since customers are low volume users, with highly seasonal demand and have little flexibility in their service requirements, profit margins are thin for marketers. Participating firms require significant participation by retail consumers to make a profit. Customers, on the other hand, seem reluctant to leave their local LDCs. Concerns over the quality of service available from marketers may be contributing to this lukewarm response. Another issue is price. Since most LDCs do not add a profit margin to commodity prices, except in special cases, there has been little price incentive for retail customers to switch to marketers.

Though the exact formula varies from jurisdiction to jurisdiction, typically utility boards use a COS approach for rate setting. In general, LDC rates are broken down into various components including a gas supply cost and a delivery charge. The delivery charge includes transmission, storage and load balancing costs as well as a "reasonable" rate of return on capital. Typically, LDCs are not permitted to make any profit on the commodity price of gas.

Faulhaber has argued that if a cross-subsidy exists in a regulated market, and if that system is opened to competition, then those participants who can do better will leave. When wholesale gas markets in Canada and United States were deregulated in the mid-1980s and large end users were given the choice of continuing to receive service from their LDC or buying gas from marketers or producers, the bulk of electric utilities, industrial and large commercial users in both economies opted for direct sales. In Canada, 98 percent of industrial users and 30 percent of commercial users in some provinces, currently buy their gas from marketers [National Energy Board, 2000e]. In the United States, 87 percent of the gas purchased by electric utilities, 91 percent purchased by industrial customers and 35 percent of gas used in the commercial sector came from non-utility suppliers in 1998 [American Gas Association, 2000b].

Before deregulation, LDCs had different customer categories and charged high load, low distribution cost customers lower rates than low load residential and commercial customers. However, despite this practice, almost all large end users abandoned LDCs after deregulation. This fact implies that large end-users were paying prices that were higher than the actual cost of service. Traditionally, regulators have designated LDCs as the "supplier of last resort" for all gas users in its service area. To serve in this capacity, LDCs must incur additional costs such as maintaining extra capacity on pipelines and in storage for emergencies. LDCs were likely passing some of the costs of this service onto industrial users. Further, LDCs served as sole supplier for core residential and commercial customers that have low load factors but inelastic demand for service. Large end users were likely subsidising the distribution costs to core customers too.

In a deregulated market, LDCs largely serve residential and small commercial customers. These customers have a similar demand profile and are expensive to serve. In the United States, where some states have unbundled retail gas service, the local LDC has been freed of its responsibilities as "supplier of last resort," but for the most part, LDCs are mandated to provide these services. The cost of this service is passed onto consumers through the distribution charge. Now, captive customers absorb the full cost of their service plus the insurance policy of a guaranteed gas supply.

Retail gas competition in the United States is available in 22 states and the District of Columbia, but only about 22 percent of eligible customers have chosen to leave their local LDCs [Energy Information Administration, 2000d]. In Canada most provinces have opened up their markets to competition as well. In British Columbia, Alberta and Saskatchewan, few customers have opted for direct sales from gas marketers whereas in Manitoba (20 percent), Ontario (around 50 percent) and Quebec (around 40 percent) a significant portion of the retail market has made the switch [Natural Resources Canada, 2000]. In both economies, LDCs are not permitted to mark up the commodity price of gas and the customer pays the LDC for distribution whether he contracts the gas from the LDC or the marketer. It therefore seems unlikely that consumers are being driven to gas marketers because of cross-subsidies. In Georgia where participation levels are 100 percent, customers were forced to switch to gas marketers when the local LDC, Atlanta Gas Light exited the retail market on 1 October 1999 [American Gas Association, 2000c]. In Manitoba, Ontario and Quebec, marketers were able to make inroads due to temporary market conditions that allowed them to offer gas at lower prices than utilities. Marketers have been able to maintain market share because they offer consumers a different product from LDCs: fixed prices. To promote competition, utility boards have not permitted LDCs to offer similar terms.

Though it appears that deregulation has eliminated indirect price subsidies in Canada and the United States, income targeted energy subsidies are currently available. The removal of transportation bottlenecks funnelled gas to export markets and has pushed up gas prices in Canada since 1999. In late 2000, the federal government in Canada announced an energy rebate for low-income households ranging from CDA$125 to a maximum of CDA$250 per year [Canadian Broadcasting Corporation, 2000]. In the United States, the federal government created the Low Income Home Energy Assistance Program in 1981. This programme gives funds to state governments for energy assistance to low income households. The programmes available vary from state to state, but on average, eligible households received

US$180 in assistance in 1996 [Energy Information Administration, 2000e].

In the energy-rich province of Alberta, Canada gas rates for residential consumers for winter 2000 increased by 235 percent relative to the previous year [Hall, 2000 and Farrell, 2001]. The provincial government, which is earning substantial oil and gas royalties, has announced a series of blanket energy rebates to combat rising energy prices and to return some of the "benefits" of the province's resources to its citizens. A one-time natural gas rebate programme worth CDA$600 per Alberta household, was announced for January-April 2001 [Jeffs, 2001].

On the Canadian East Coast, the Sable gas field off Nova Scotia began pumping gas in December 1999. Gas became available for the first time in the local maritime market in late 2000. To attract residential, commercial and industrial customers, LDCs in Nova Scotia and New Brunswick intend to guarantee customers prices that are lower than competing fuels. Incentives to encourage fuel switching will also be offered [National Energy Board, 2000e]. In this case subsidies are being used to build a customer base in a new gas market.

MEXICO[18]

Mexico will face a strong increase in natural gas demand, which is projected to grow at an average annual rate of 8.7 percent for the next 10 years. Much of this growth in demand is due to the implementation of a fuel substitution policy within the electric industry, together with the growth of the industrial, oil and residential sectors. Many thermoelectric plants are being converted from fuel oil to natural gas, both for economic and environmental reasons. The Federal Government's fuel policy promotes the use of new technologies based on natural gas, such as combined cycle.

Since 1992, the legal and institutional framework has been revised to allow private participation in activities such as transportation, storage and distribution of natural gas. Other areas that have been opened to private investment in the energy sector include the non-basic petrochemical industry, electricity generation for self supply, cogeneration, and independent power production.

Article 27 of Mexico's Constitution and its regulatory Law on Petroleum govern the oil and natural gas industry in Mexico. These laws are aimed at regulating first-hand sales and natural gas activities and services open to private participation in order to ensure efficient supply. Activities reserved for government are exploration, production and first-hand sales of natural gas. Pipelines will continue to be Federal property, with long-term concessions granted to private operators.

Activities open to private investors are construction, operation and management of transportation systems, storage and distribution related to natural gas. These activities are subject to regulation by the Energy Regulatory Commission (CRE, for its initials in Spanish). CRE is responsible for granting operations, import and export permits to interested parties. Natural gas commercial, export and import activities have also been liberalized.

Petroleos Mexicanos (PEMEX) is the only natural gas producer allowed by law; in 1999 it supplied 98 percent of national demand. In 1999 the oil industry sector was the major consumer, with 40 percent of national demand followed by the industrial sector with 36.7 percent and the electric sector with 20.7 percent. Major large-volume consumers include government owned electric utilities such as Comision Federal de Electricidad (CFE), Luz y Fuerza del Centro, PEMEX and its subsidiaries. Annual gas consumption averages 14,950 cubic feet per capita and per capita gas pipeline length is 0.4 metres.

Regulations state that the maximum price of first-hand sales shall be set in accordance with directives issued by the CRE. The price setting methodology is based on the opportunity cost of gas in competitive conditions in international markets, plus the transportation and distribution costs. The maximum price of gas does not affect the right of the purchaser to negotiate more favourable conditions in the purchase price.

Concerning first-hand gas sales, PEMEX offers purchasers at least two price quotations for a specified volume that are considered offers to sell at the following locations:

- At the point of exit from a processing plant; and,
- At a point or points of delivery specified by the purchaser that shall separately state the transportation rate and the gas price at the point of exit from the processing plant, as well as any other services offered by PEMEX.

CRE regulates the components of end-user price to ensure that final consumers who purchase gas services from distributors pay no more than the regulated first-hand sales price plus the authorised transportation and storage rates. The regulated acquisition price will allow distributors to recover the costs of: the acquisition of gas at a price less than or equal to the weighted average reference price which would normally be the maximum first-hand sales price; and the contracting of transportation service utilising appropriate routing and storage services, at the CRE's approved rates. Depending on user and the process centre, an average of 60 percent represents the cost of natural gas for the end-user, and 40 percent represents the transportation and distribution costs.

The price is revised on a monthly basis; it is generally seasonal and depends on the opportunity cost which reflects supply and demand in the reference market, south of Texas, U.S.A. This price is set according to the netback methodology, plus the transportation and distribution cost.

Rates include connection, capacity and consumption charges. Differences may be established according to:

- Type of service;
- Category and location of user;
- Service conditions; and,
- Other generally accepted factors in the industry.

Contracts allow permit holders to offer special rates depending on contracted volume; contract rates for interruptible services must be below the corresponding firm rate but higher or equal to the minimum rate for firm rate services.

SUMMARY

- In Canada and the United States the deregulation of gas markets has been successful. Despite rapid growth in natural gas consumption, end use prices at first declined and remained stable until 2000.
- Gas markets in Canada and the United States have become more closely integrated since deregulation due to a favourable regulatory climate that has encouraged pipeline interconnection and exports.
- The commodity price of gas has been completely deregulated and is now market determined; however, high-pressure transportation systems and retail distribution remain

regulated monopolies.

- Deregulation may have eliminated or reduced cross-subsidies in transportation rate structures and in retail distribution markets. At the same time, due to efficiency gains in commodity gas market, overall inflation-adjusted prices for all classes of consumers have fallen.

- In transportation, there is no evidence of cross-subsidies in cost-of-service or existing negotiated transportation tolls. Regulatory changes over the last two decades have helped to encourage more transparent and competitive regulated transportation rates.

- In distribution, there is no evidence of existence or non-existence of cross-subsidies. Retail markets are slowly being opened up to competition. However, gas marketers have had difficulty attracting customers from LDCs.

SOUTHEAST ASIA

This section reviews pricing practices for natural gas end uses in APEC-ASEAN member economies: Brunei Darussalam, Indonesia, Malaysia, the Philippines, Singapore, Thailand and Viet Nam. Firstly, a brief description of domestic gas markets in the region is provided, and then, based on data availability, some key issues relating to end use gas pricing such as: the institutional framework, the process of price setting and policies on natural gas pricing in these member economies are examined.

DOMESTIC USE OF NATURAL GAS IN SOUTHEAST ASIA

As indicated in APERC's project on Natural Gas Infrastructure Development (Southeast Asia) last year [APERC, 2000], there has been a steady increase in natural gas consumption in Southeast Asia in the period 1990 -1998, with an average increase of 9.5 percent per year. The economic crisis of 1997-98 did not seem to have had much impact on natural gas consumption.

The large increase in the share of natural gas in regional energy demand is a direct result of initiatives taken by Southeast Asian economies to reduce their high reliance on oil and oil products, as well as the region's strong awareness and concern regarding the environmental impacts of energy use. Natural gas, as a premium fuel and an environmentally friendly alternative to oil and coal, is a natural choice to take an increasing share in energy markets.

The power sector is the largest consumer of natural gas in Southeast Asia. Brunei Darussalam, for example, has 99 percent of its power generated by natural gas while Malaysia, as part of its diversification policy, now has around 73 percent of its power supplied by gas-fired plants (1999), compared to 98 percent from oil fifteen years ago. Viet Nam started using associated gas for electricity generation in 1995 and its share of total electricity production has rapidly increasing from 0.1 percent in 1995 to 18.2 percent in 1998. Currently, all extracted gas is used for generating electricity (1999). In Indonesia, where coal is the major fuel for electricity generation, the amount of natural gas burned in power plants is comparable to its direct use in industry. Most of the natural gas consumed in the industrial sector is used as feedstock for fertiliser production.

INSTITUTIONAL FRAMEWORK

BRUNEI DARUSSALAM

Brunei Oil and Gas Authority (BOGA) is the regulatory agency for oil and gas activities formed on 1st January 1993. Its main functions are to provide advice and recommendations on policies in all matters relating to oil, gas, products and their implementation as well as planning and control of activities with regard to the development of these markets.

Brunei Shell Petroleum Sdn Bhd (BSP), the national oil company, is a major player in the gas industry. It is engaged in the exploration and production of oil and gas. It currently operates two onshore fields and seven offshore fields.

Brunei Liquefied Natural Gas (BLNG), a joint venture between the Brunei Darussalam government, Shell International and Mitsubishi Corporation, liquefies natural gas purchased from BSP and exports it to Japan and Korea.

The Brunei Shell Tankers Sdn Bhd (BST) operates LNG carriers to transport LNG. The Brunei Shell Marketing Sdn Bhd (BSM) manages the local marketing of petroleum products and bottled LPG for domestic use. The Jasra-Elf Joint Venture (JEJV) operates offshore concessions after the discovery of the Maharaja Lela-Jamalul Alam oil and gas fields.

INDONESIA

The responsibility for enacting gas regulations in Indonesia lies with the Ministry of Mines and Energy under the Directorate-General of Oil and Gas. National energy policies for the development and utilisation of energy resources are, however, coordinated by the National Energy Coordinating Board (BAKOREN).

There are two major players in the domestic natural gas industry: The National Oil and Gas Company (Pertamina) and P.T. Gas Negara (PGN). Pertamina undertakes gas exploration and development, transmission, and production in collaboration with international operators (mostly with respect to offshore fields). It is the only authorised supplier of gas to very large gas customers such as power and petrochemical plants. PGN is a state owned company responsible for the distribution and marketing of natural gas. It buys gas from Pertamina and sells it to consumers. As part of Indonesia's further restructuring in the energy sector, PGN plans to restructure into a holding company by creating subsidiaries to undertake its principal business activities.

MALAYSIA

In Malaysia, the Prime Minister's Department plays a key role in all petroleum matters. Within the department, the Economic Planning Unit (EPU) is in charge of policy formulation, and the Implementation and Coordination Unit (ICU) is responsible for petroleum development. PETRONAS carries out exploration, development and production activities. Through its wholly owned subsidiary, PETRONAS-Carigali Sdn Bhd (PCSB), PETRONAS has production sharing contracts with a number of international oil and gas companies. Another subsidiary, PETRONAS Gas Bhd (PGB), is responsible for the trans-peninsular pipeline and gas processing. Another company, Gas Malaysia Sdn Bhd (GMSB) distributes the gas to users via the natural gas distribution system.

The Department of Electricity and Gas Supply, under the Ministry of Energy Communications and Multimedia, is the body that regulates electricity and natural gas supply in the economy.

Natural gas demand in Malaysia can be divided into four major markets, namely: power generation, petrochemical feedstock, domestic and industrial consumption, and LNG exports. Of the major uses, gas processing currently accounts for around 21.1 percent of total gas primary production, LNG exports 43.3 percent and power generation 20.5 percent [Ministry of Energy, Communications and Multimedia, 2000].

THAILAND

According to the Petroleum Acts of 1971, the government owns all the economy's oil and gas resources and it can award concessions and other rights for exploration and production to qualified bidders that seek to invest in oil and gas exploration. If commercial quantities of natural gas are discovered, the concessionaire will negotiate a long-term or life-of-field contract to sell the gas to the Petroleum Authority of Thailand (PTT).

Thailand's National Energy Policy Office (NEPO) formulates and analyses energy policies and reports to the Prime Minister's Office. PTT, the national oil and gas company, procures and produces natural gas through its subsidiary, PTT-Exploration and Production (PTTEP). In addition, PTT is also responsible for the transmission and distribution of natural gas to consumers. Major foreign oil companies are involved in technical operations such as gas exploration and development through contractual arrangements with PTT.

Large gas consumers are: The Electricity Generating Authority of Thailand (EGAT), The Electricity Generating Company (EGCO), independent power producers (IPPs), small power producers (SPPs), and the petrochemical industry. Electricity generation is the largest consuming sector accounting for 70 percent of total natural gas consumption annually.

PHILIPPINES

The Department of Energy (DOE) which is responsible for Philippine energy matters and policies coordinates the activities of key energy institutions in the economy, including the Philippine National Oil Company (PNOC), which undertakes the development of the economy's indigenous geothermal, oil and natural gas resources. The DOE awards service contracts for the exploration and development of indigenous resources.

Natural gas is a relatively new industry with PNOC-Exploration and Corporation (PNOC-EC) having discovered and developed a small gas field, Camago-Malampaya, in San Antonio, Isabela in Luzon. The development of Camago-Malampaya is planned for completion in 2002. At present and in the near future when the Malampaya project will be completed, natural gas is planned for power generation use only.

SINGAPORE

The Ministry of Trade and Industry, Singapore has several roles in the energy sector including formulating energy policies, monitoring trends in the energy sector, and supervising the Public Utilities Board (PUB), the Economic Development Board, and the Department of Statistics. PUB is the regulator for the electricity and piped gas industries. The piped gas undertaking was vested in PowerGas Ltd. Therefore, PowerGas is authorised to manufacture and distribute through a current gas distribution network of 2,500 km of pipelines to consumers. The Fire and Safety Bureau of the Singapore Civil Defence Force regulates LPG transportation.

Natural gas is currently used only for power generation. It is supplied directly to the power plants through dedicated pipelines.

VIET NAM

The Ministry of Industry (MOI) and Government's Office set energy policies and administers the energy master plan. The State Price Committee (SPC) is responsible for evaluating and submitting energy prices to government. PetroVietnam, a state-owned oil and gas corporation, carries out all petroleum-based operations. Foreign oil companies may enter into joint exploration with PetroVietnam through production sharing, business cooperation, or joint venture contracts. PetroVietnam is responsible for oil and gas exploration, and the production, transmission and distribution of associated gas. Particularly, PetroVietnam Gas Company (PVGC) is a PetroVietnam subsidiary that is responsible for distribution of gas from the White Tiger field to customers. Petrolimex, directly controlled by the Ministry of Trade and Tourism (MOTT), is responsible for petroleum products distribution including LPG.

To date, associated gas produced from the White Tiger crude oil field has been supplied mainly to power plants and, since early 2000, to a lesser extent to a gas separating plant for the production of LPG.

The institutional framework for gas in Southeast Asia is summarised in Table 2.

GAS PRICE SETTING

Generally, the price of natural gas paid by consumers is based on the volume of gas delivered, and is made up of three parts:

a) The transmission cost of moving the gas by pipeline from its source to consuming areas,

b) The distribution cost of moving the gas from within the local area to the user's location,

c) The cost of the gas itself.

In addition, it is clear that the price of gas includes fixed cost components of transmission and distribution that are charged independently of the level of consumption. As a result, the averaged unit cost of gas may increase as the amount of gas consumed declines. However, natural gas pricing policies in most Southeast Asian economies are influenced not only by economic objectives but also by the social objectives of each economy. Thus, the end-use prices of natural gas are generally not entirely market-based. However, developments in energy pricing and market structure in the ASEAN member economies are clearly towards the commercialisation and privatisation of state companies, deregulation of energy markets, and competitive market prices. Differences exist between member economies and across energy sectors in both the pace and process of change. Natural gas pricing in Singapore quite clearly reflects market conditions, while in Brunei Darussalam and Viet Nam social objectives still play an important role in the determination of gas prices, though both economies have prepared plans for a gradual shift to market-based pricing. Malaysia and the Philippines are gradually adopting market pricing, although both still take into account social considerations. In Indonesia, it seems that a compromised combination of economic, social and financial objectives has been introduced in setting gas prices. In Thailand, the government bases its pricing policies on production costs and transmission costs as well as on negotiation between producers, distributors, and consumers. As previously mentioned, PTT is currently a monopoly in the transmission and distribution of natural gas to consumers. NEPO is now proposing to increase private sector participation in gas transportation.

Table 2 Institutional Framework for Gas in Southeast Asia

Economy	Regulatory Agency	Production/ Contract Type	Transmission	Distribution in Domestic Markets	Consumers
Brunei	Brunei Oil and Gas Authority (BOGA) Petroleum Unit Brunei National Energy Committee Department of Electrical Services, Ministry of Development	Brunei Shell Petroleum Sdn Bhd, Brunei Coldgas Sdn Bhd, Jasra-Elf Joint Venture (JEJV)/ Competitive Bidding	Gas Pipeline: BSP LNG Pipeline: Brunei LNG Sdn (BLNG) Brunei Shell Tankers (BST)	Brunei Shell Marketing Company Sdn Bhd (BSM)	Piped Gas for power plants LPG for households LNG for export
Indonesia	National Energy Policy Board (BAKOREN) Ministry of Mines and Energy, Energy Resources Technical Committee	Mobil, Vico, Total, Arco, UNOCAL, Asamera, Caltex, and Exxon sharing contracts with Pertamina/ Production Sharing	Pertamina	Pertamina and Perum Gas Negara (PGN)	53 % - Pusri, Pupuk, Kuyang, Pupuk Kaltim, Pim, Petrokimia Gresik (fertiliser companies), 9 % -Perusahaan Umum Listrik Negara (PLN) 14% - Krakatau Steel Company, 14 % -refineries, 10 % - Independent Power Producer (IPPs)
Malaysia	Prime Minister's Department Advisory bodies (Cabinet Committee, Petroleum Development Council) National Petroleum Advisory Council) Department of Electricity and Gas Supply (Ministry of Energy, Communications and Multimedia)	PETRONAS, PETRONAS Carigali Sdn Bhd (PCSB), Esso Production Malaysia (EPMI), Sarawak Shell Berhad (SSB), Sabah Shell Petroleum Company (SSPC), Occidental (Malaysia) Ltd / Production Sharing	Gas Pipeline: PETRONAS Gas Bhd (PGB) LNG Pipeline: PETRONAS	Gas Malaysia Sdn Bhd (GMSB)	Tenaga Nasional Berhad (TNB), IPPs, Petrochemical Plants, Sabah Electricity Board (SEB), Sarawak Electricity Supply Company (SESCO) Iron, Steel and Petrochemical Companies
Philippines	Department of Energy (DOE) Energy Regulatory Board National Economic and Development Authority	Philippines National Oil company (PNOC) via PNOC exploration, Shell/Occidental Philippines Consortium/ Service Contract	First Gas Holdings Corporation (FGHC)	Manila Gas Company	Only for power generation National Power Corporation (NAPOCOR), IPPs
Singapore	Ministry of Trade and Industry (MTI), Public Utilities Board (PUB)	PowerGas Ltd (production of town gas)	PowerGas Ltd	PowerGas Ltd	Piped Gas for power plants LNG, LPG for domestic, commercial and industrial consumers
Thailand	National Energy Policy Council (NEPC), National Energy Policy Office (NEPO), Department of Mineral Resources (DMR), Ministry of Industry Department of Energy Development and Promotion (DEDP)	UNOCAL, PTTEP, Total, Thai Shell Exploration and Production Ltd, Esso Exploration and Production Inc / Concession	Petroleum Authority of Thailand (PTT)	PTT	Power sector: Electricity Generating Authority of Thailand (EGAT), Electricity Generating Company (EGCO), IPPs, Small Power Producers (SPPs) Petrochemical industry
Viet Nam*	Prime Minister's Office Ministry of Industry (MOI) Ministry of Finance (MOF) State Price Committee (SPC) Ministry of Trade and Tourism (MOTT)	Vietsopetro, PETRONAS Carigali, Total, Sumitomo, PetroVietnam Gas Company/ Production, Business Corporation, or Joint Venture	Gas pipeline: PetroVietnam Gas Company (PVGC) Bottled LPG: Petrolimex and other joint venture companies	PetroVietnam Gas Company (PVGC) Petrolimex and other joint venture companies	Piped gas for power sector (Electricity of Viet Nam-EVN) LPG for household and commercial sector

Source: CEERD, 1999, AEEMTRC, 1996
* Institute of Energy, Viet Nam, 2000

In Brunei Darussalam and the Philippines, gas producers also participate in downstream activities such as gas transmission and distribution. Therefore, wellhead prices can be calculated by subtracting transmission cost from consumer prices on a netback basis. In Indonesia, Malaysia and Thailand, where major gas producers are not involved in downstream activities, producer prices are determined by contract arrangement between the sellers and buyers with the involvement of upstream producers and downstream purchasers. An example can be found in Malaysia, where natural gas sold by upstream operators is indexed to the prices of marine fuel oil ex-Singapore. In Thailand, natural gas prices are determined by an agreement between the gas field operators and PTT. The gas is piped to terminals or consumers such as EGAT and is resold to different consumers at different prices [Pacudan and Lefevre, 1998]. In Viet Nam, it seems that the government bases the price of associated gas mainly on transmission costs and retail prices of electricity. As electricity prices are highly subsidised, the associated gas price for power generation is subsidised partly by PetroViet Nam.

Table 3 Consumer Gas Prices and Taxes

	Brunei Darussalam	Indonesia	Malaysia	Thailand	Viet Nam*
			US$/MMBtu		
Power generation	0.33	2.5-3.0	3.4	2.69	1.75
Residential	0.17	3.46	6.8	-	-
Commercial	0.3	3.46	6.4	-	-
Industry:	-	-	4.3	-	-
- Fertiliser	-	1.0-1.5	-	2.69	-
- Petrochemical	-	2.0	-	2.69	-
- Steel	-	0.65-2.0	-	-	-
- Cement	-	3.0	-	3.17	-
- Ceramic	-	-	-	4.91	-
- Others	-	-	-	4.22	-
Consumer taxes	No taxes on gas sales	No tax on gas sales	No tax on gas sales	VAT of 7%	-

Source: Pacudan, 1998
Institute of Energy, Viet Nam, 1999

Price differentials exist between different consumer groups and locations. In rate structure regulation, price discrimination is a monopoly practice where a monopoly serves different markets, different locations and is in a position to raise profits by discriminating between them. A structure of prices may be developed where differences in prices charged to different groups cannot be accounted for by the differences in cost. In practice, prices may be set according to such factors as differences in demand and willingness and ability to pay. Some indication of these practices can be found in ASEAN member economies, as shown in Table 3. For example, in the case of Indonesia, pricing structures of natural gas reflect a policy of subsidising the fertiliser and steel industries. In the case of Malaysia, the prices are different between regions: Peninsula, Sarawak and Sabah. In Thailand, PTT is planning to begin eliminating the price disparity in natural gas that it sells to various customers. PTT has been selling gas to EGAT and independent power producers at cost plus margins of 1 percent to 1.5 percent while charging small power producers a margin of 9 percent. PTT has reached a consensus to put the fuel prices charged to all power producers on an equal basis to enable them to compete effectively when the power pool is introduced in 2003.

Some recent end-use price changes are available for a number of economies. The reasons for and the process of adjustment for these changes are different. In the case of Viet Nam, the major reason is that the producer cannot accept the low price and the government wants to reduce subsidies gradually by periodic increases in the price to approach the market level. Generally, the price has been revised once a year. On the other hand, in Singapore, prices are already at market levels. Therefore, the process of

Table 4 Changes in Gas Prices in Selected ASEAN Member Economies

Economy	Unit	1996	1997	1998	1999	Remark
Thailand	Baht/MMBtu	79.81	93.45	106.49		For power generation
Viet Nam	US$/MMBtu	1.15	1.75	1.87	2.00	For power generation

Source: PetroVietNam, Internal Discussion Paper; Institute of Energy, Internal Discussion Paper, 1999; APERC Database.

price revision varies entirely with the fluctuation of prices in markets and these changes are irregular (Table 4).

In terms of the method of gas pricing, the indexing of gas prices to the price of substitute petroleum products raises important concerns in gas pricing in Southeast Asia. The concern is rooted in the possibility that the price of the indexed fuel may decline continuously to the point where revenues generated by natural gas producers, transporters and distributors would be insufficient to cover investment and operating costs. If this trend were sustained for a long period of time, government may be forced to augment gas prices to protect domestic producers. On the other hand, governments are also concerned that gas companies might be receiving undue benefits from higher gas prices. In many cases the long-run marginal cost of production and market prices are used to represent the lower and upper limits and the effective price of natural gas is negotiated in between.

Another related concern is the reference prices of the indexed substitute fuels. While gas prices for the power sector are pegged to the average Singapore-posted prices of medium fuel oil (MFO) in Malaysia and Thailand, gas prices for other sectors are indexed to the local prices of petroleum products. This raises the question on the appropriateness of the reference prices since domestic petroleum prices in most of these member economies do not reflect the economic scarcity of the resource, due to the government's distortionary taxes and subsidies [Pacudan, 1999].

For Indonesia, at present in the third stage of price increases, in which gas is priced based on its netback value, which equals to all costs required to change the system to substitute other fuels with gas. In the future the price of gas should no longer be linked to the price of crude oil, and instead have a higher value than its netback value taking account cleanness and efficiency. Prices for large-scale users such as power plants operated by IPPs are negotiated directly between the suppliers and the buyers. The gas price to fertiliser manufacturers is heavily subsidised as a result of a policy to provide Indonesia's farmers with inexpensive fertiliser. The gas price to other industries is pegged to residual fuel oil prices. The transmission charges for gas pipeline operators are also negotiated between the pipeline operators and users. Gas prices in the residential and transport sectors, which are small in scale, are subsidised. For the residential sector, the gas price is set based on the kerosene price, and for the transport sector the price is set at half the price of gasoline to encourage motorists to use CNG for their vehicles.

For the end-uses of natural gas in Southeast Asia, as shown in Table 3, only Thailand imposes a VAT (of 7 percent) to gas sales, while other economies like Brunei Darussalam, Malaysia and Indonesia do not levy taxes on domestic sales.

POLICIES ON NATURAL GAS PRICING

Economies such as Indonesia, Malaysia, Thailand and the Philippines place a high priority on encouraging private sector participation and foreign investment in resource development including natural gas. The remaining ASEAN economies such as Brunei Darussalam and Viet Nam are also improving their investment environments to attract domestic and foreign capital and have achieved promising results in recent years.

BRUNEI DARUSSALAM

With power generation in Brunei Darussalam fired almost entirely by natural gas, energy policy measures have been introduced to achieve the following objectives: expanding the use of alternative energy sources; encouraging private sector participation in energy development; considering only the most efficient types of power plants; revising energy prices to increase awareness of true energy costs and to discourage energy wastage; and promoting energy efficiency in building design and materials choice. The government is considering coal or fuel oil as alternative fuels to avoid being heavily dependent on gas as a fuel [IEA, 1996].

Brunei Darussalam has recently formulated an action plan to gradually adopt a market based pricing system. However social equity remains a dominant factor in energy pricing policy. With respect to natural gas development and production, historically a concession type of contract has been used where the government secured rent, firstly through signature bonuses during the transfer of rights, and secondly through royalties, taxes and rental during the production phase. Now Brunei Darussalam has adopted a competitive bidding arrangement for oil and gas exploration.

INDONESIA

Indonesia has adopted five principal policies related to natural gas development, namely: energy diversification; intensification of exploration for energy sources; energy conservation; equitable energy price setting; and environmental protection. Emphasis is placed on diversifying the sources of energy supply, both renewable and non-renewable. This policy operates within a framework of economic optimisation and sustainable development. It is focused especially on those energy sources that are not exportable or not available in great quantities. In this respect, natural gas can play a role as an alternative for fuel oil for domestic energy use [NECB, 1998].

Through the development of pipeline networks Indonesia also places a high priority on promoting the domestic use of natural gas.

It also encourages private sector participation and foreign investment in its resource development. The government aims to do this by liberalising the gas supply industry and removing the monopoly and quasi-regulatory role of the state oil and gas company, Pertamina. The distribution arm of PGN Pertamina will become a commercially focused company and its role will be to manage production sharing. Other upstream contract arrangements would be taken over by the Ministry of Mines and Energy. PGN would be separated into transmission and retail companies, and opened to public shareholding, while the producer would sell directly to consumers [Financial Times, 1999].

Some natural gas pricing policy changes were made in the early 1990s to encourage foreign investment in gas development in marginal areas and to increase the size of the domestic market. More recently, the government has promised to remove natural gas price subsidies to all consumers except fertiliser plants. However, price subsidies for natural gas used for fertiliser manufacture are to be reduced.

MALAYSIA

The Malaysian government's energy policy objectives are: to ensure adequate energy supply by reducing dependence on oil; to promote the efficient use of energy and discourage wasteful and non-productive patterns of energy consumption; and to minimise environmental degradation in realising the above goals. In mid-1999, Malaysia updated its four-fuel policy (oil, gas, coal and hydropower) to include renewable energy as the fifth fuel.

Gas will assist the government to achieve the above objectives. According to the Sixth Malaysia Plan (1991-1995) government policy was to expand the use of natural gas as a source of primary energy to substitute for oil. The PGU network was established during this period. Another objective is to increase the export of LNG to boost foreign exchange earnings. Malaysia also has a policy of seeking to add value to its resource exports, including natural gas. Consequently, the government does not support additional sales of gas to Singapore or Thailand, but instead prefers the value-added export of petrochemical products that use natural gas as a feedstock [IEA, 1999].

The Malaysian government has removed signature bonuses in their contracts with gas producers and replaced them with production sharing arrangements. In addition, the government is progressively adopting market prices. On the other hand, in order to reduce CO_2 emissions, the government encourages the use of natural gas vehicles (NGV) by setting the retail price of natural gas at half the price of petrol.

PHILIPPINES

The government views the use of natural gas as an option to further reduce dependence on imported oil. Considering the environmental advantages of natural gas, there are also strong incentives for the government to encourage gas market expansion to other end-use markets including industrial, commercial, residential, and transport sectors [ACE, 1999].

Under the Philippines Constitution, the exploration and development of natural gas and other similarly sourced natural endowments can be done on a production sharing agreement scheme. The Department of Energy (DOE) is given the discretion to enter into contracts as long as the annual net revenue share for the government including taxes is not less than 60 percent.

SINGAPORE

The government actively diversifies Singapore's energy sources. Since January 1992, natural gas from Malaysia has been used for electricity generation. As a step towards energy supply diversification, Singapore is expanding its natural gas use through new supply from the West Natuna field in Indonesian waters.

There are no energy subsidies in Singapore. By allowing the price of energy to reflect the current international market price of fuel ensures that energy is being used efficiently. Prices for the piped gas supplied by PowerGas Ltd and fuel oil, diesel etc. by the oil companies, are set by the individual private companies and reflect international market prices of fuel.

Singapore is in the process of deregulating its electricity and gas sectors by separating the ownership of the gas transportation business, which is a natural monopoly, from the contestable sectors of gas import, trading and retailing. The entire gas distribution and transmission network will be owned by a gas grid company, which will allow suppliers open and non-discriminatory access to the network.

THAILAND

The key objectives of Thailand's energy policies are: to ensure the continued availability of energy supplies; to increase the role of the private sector in energy markets by deregulation, privatisation and the encouragement of competition; to remove barriers to market pricing; to promote energy conservation through greater energy efficiency; and to minimise the environmental problems associated with energy consumption. National policies give priority to gas as a fuel for power generation, as a substitute for fuel oil, and as a feedstock for petrochemicals, in industry, and in agriculture [IEA, 1999].

The change of policy occurred in the second half of the 1980s, during the slackening of world oil prices. For many years in the past, the cost-plus pricing method was adopted in Thailand. Currently, along with restructuring of the gas industry, moves toward more market-related pricing are occurring. The government wants to promote competition in the industry, which will lead to increased efficiency and increase incentives to reduce production costs, which, in turn, will lead to increased competitiveness of the industry overall.

In the near future, the PTT transmission and distribution systems will be separated from the gas trading system. PTT Transmission Co. Ltd. will be established as a wholly owned subsidiary of PTT and will be solely responsible for transmission activities. Third Party Access (TPA) to transmission services will be introduced to promote competition in the gas supply industry.

The regulatory work will be separated into two phases: the short and the long term. In the short term, NEPO, on behalf of the NEPC, PTT and other related agencies will supervise and regulate the natural gas business. In the long term, an independent regulator will take over all responsibilities from the authorities previously regulating the business.

VIET NAM

Viet Nam is undertaking reform of the energy sector in respect of institutional structures, energy pricing and energy financing. The main objectives of energy policy in Viet Nam are: the diversification of energy resources based on development of indigenous energy resources and expansion of regional energy cooperation; ensuring adequate energy supplies to meet the energy demand of socio-economic development and population growth; and employing energy conservation and efficient energy use as important energy resources for developing the economy and reducing negative environmental impacts.

The pricing of natural gas is a relatively new issue in Viet Nam. According to a recent study on energy pricing policy, gas prices should be responsive to market conditions and discriminate between different use objectives such as power generation, industry and residential sectors. In addition, gas prices must lie between the floor price and the maximum market value.

SUMMARY

- The development of the utilisation of natural gas in Southeast Asia has accelerated during the last few years, with the main use being power generation, especially in Thailand and Viet Nam. There has been a steady increase in natural gas consumption in the period of 1990-1998, with an average growth rate of 9.5 percent per annum. The Asian economic crisis of 1997/98 did not seem to interrupt or slow this trend.

- Indonesia and Malaysia have enough reserves for both domestic supply and exports. Most of the ASEAN economies have policies that encourage foreign investment in resource development. There is also a common policy objective to enhance domestic gas production and utilisation.

- Natural gas pricing policies in most Southeast Asian economies are not only influenced by economic objectives such as in Singapore and Thailand, but also by the social objectives of each economy, especially in Brunei Darussalam, Indonesia and Viet Nam, while Malaysia and the Philippines are making a gradual policy shift from less emphasis on social considerations to more emphasis on market-based pricing. Thus, generally, end-use prices are not entirely determined by the market. Some economies apply subsidies to encourage the use of cheap gas for strategic industries, such as the fertiliser and steel industries in Indonesia.

- By sector, the gas price charged for power generation is generally the lowest in this region, except in Brunei Darussalam, where the lowest prices are those paid by residential consumers. There are no consumer taxes in gas prices except in Thailand where there is a VAT of 7 percent.

- While the different economies in this region employ a range of pricing practices, there is a tendency to move towards the restructuring of their natural gas industries from ones based on regulated pricing, especially in prevalent in gas-rich economies, to a more market-based pricing environment.

NORTHEAST ASIA

CHINA

As the share of natural gas in total primary energy supply is low, there are no particular laws for the natural gas sector in China. Activities should follow relevant general laws in each region, while some local regulations vary widely. Traditionally, natural gas has been a sector controlled by the central and local governments, with the production, distribution and consumption run under state plans. Government decides the price. However, it differs in different regions for local policy objectives. Residential consumers get subsidies from local governments.

Table 5 Natural Gas Utilization in China

Natural gas	Total	Industry	Residential	Generation	Other use
1991	15.58	12.01	1.81	0.64	1.12
1992	15.63	11.67	2.15	0.65	1.16
1993	16.60	12.52	1.73	0.82	1.53
1994	17.08	13.81	2.00	0.83	0.45
1995	17.35	14.31	1.94	0.79	0.31
1996	17.92	14.66	1.97	0.75	0.55
Average Growth Rate	2.8%	4.1%	1.7%	3.0%	-1.3%

Source: China Energy Statistical Yearbook 1991-1996.

Four state-owned companies play a dominant role in natural gas production. Private companies are also involved in production. One LNG project is expected to begin operation in 2005 in Guangdong province. Foreign capital has been participating in the natural gas industry.

There are two types of major natural gas consumers, industrial and residential consumers. Natural gas in China is mainly used in the industrial sector and accounted for 82 percent of total natural gas consumption in 1996 with its growth rate higher than in any other consuming sector. Although the growth rate in electricity generation sector is 3 percent, the share of consumption for electricity generation is just 4 percent, while the residential sector accounted for 11 percent and others 3 percent. Major policy concerns in the industry are efficiency improvement and environmental protection.

The government on the basis of production costs and consumer purchasing power sets the price of natural gas. But the price-setting process involves negotiation between producers, consumers and government. The energy sector has traditionally been a subsidised area in China, and natural gas has been no exception. Subsidies are focused on the residential sector. The Chinese government is interested in reducing subsidies but, with the relatively low incomes of consumers, this may take a long time.

The end-use price changes irregularly and is triggered by the producer being unable to accept low prices or government reducing subsidies. No incentive regulation has been institutionalised so far. Price gaps exist for different consumers, such as residential and industrial. Seasonal variations are allowed in the industrial sector but depend on contract style. Power generation use of natural gas adopts contract price. But it is merely accepted as a general principle and the practice varies a lot.

Table 6 Selected Gas Related Data for China

	Gas Consumption per capita (m^3)	Gas Supply (billion m^3)	Length of Pipelines (km)	Population with Access to Gas (million)
1993	5.9			
1995	6.3			
1997	6.6			
1998		23.64	68,154	146.47

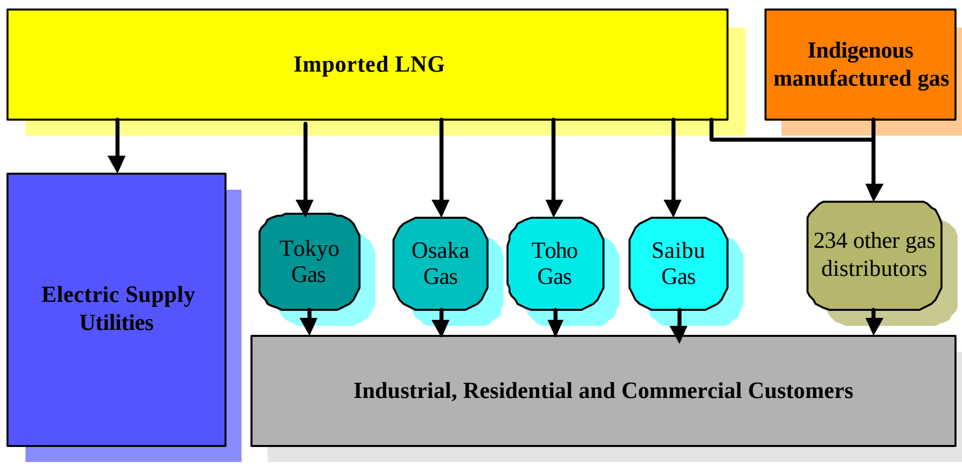
Source: China Statistical Yearbook 1999
Note: Gas includes natural gas and town gas.

JAPAN

The Japanese city gas industry has developed mainly in urban areas. Originally the government regulation allowed city gas companies to run their businesses under exclusive supply franchise areas in recognition of the huge initial investment and economies of scale. In turn, they had a supply obligation to their franchise areas after the government's price setting approval that provided a reasonable price level that protected small consumers from abuse of regional monopoly power.[20]

By taking into account the changing circumstances in the gas industry, the Gas Utility Industry Law, the main legislation governing the gas industries, was revised twice, in 1995 and 1999 respectively, for the purpose of lowering the gas price to improve economic competitiveness. This has made gas tariffs to large-volume consumers free of regulation (or approval process) in principle as long as it involves lowering rates.

Figure 5 Japanese Gas Industry Structure

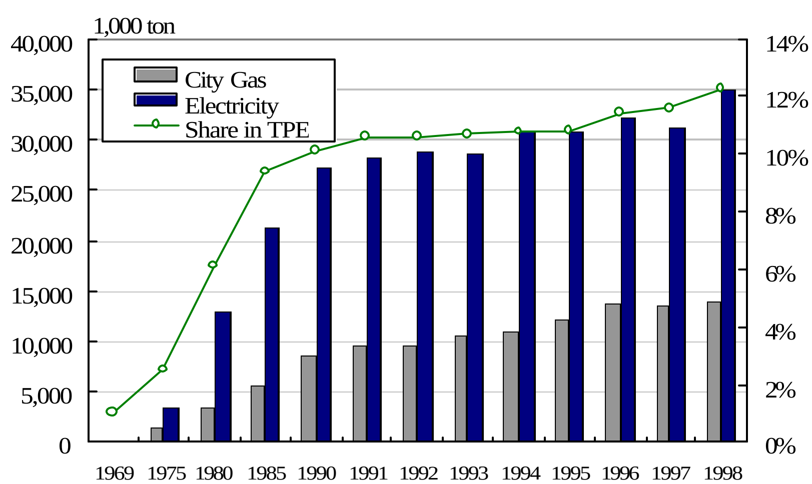


As of October 1998, there are 238 gas companies among which there are 68 public corporations and 170 private companies. Four city gas companies, namely Tokyo Gas, Osaka Gas, Toho Gas C and Saibu Gas dominate with a combined 75 percent market share. As Figure 5 shows, most of them are vertically integrated companies to which regional monopoly is permitted.

Feedstock for city gas is comprised of LNG, indigenous natural gas, coal, LPG and naphtha. In terms of sales volume, 89 percent of total volume relied on natural gas as a feedstock.

Since the introduction of LNG in 1969, natural gas consumption has grown considerably to 1998. Natural gas is used mainly for electricity generation (70.3 percent of total usage in 1998), followed by reticulated city gas (28.3 percent) and feedstock for petrochemical industry industrial fuel (1.3 percent). However, the growth in natural gas consumption has recently levelled off. The reason for the change in

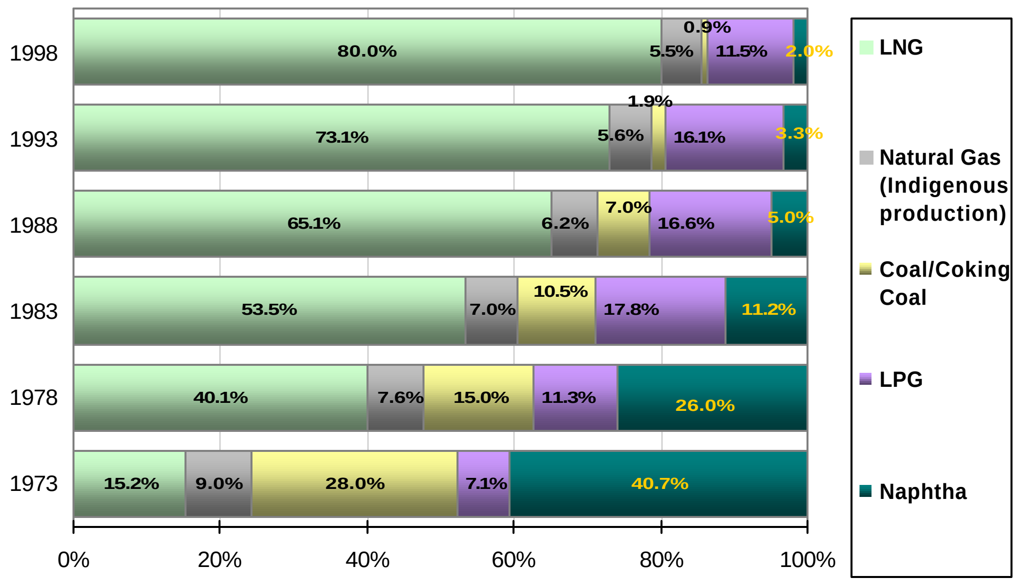
Figure 6 Natural Gas Consumption Trends by Sector for Japan



Note: Time axis not annual prior to 1990.

Source: EDMC (2000)

Figure 7 Change in the Composition of Feedstock for City Gas



natural gas consumption growth is two fold: changes in total electricity demand and changes in the energy mix. From 1980 to 1990, electricity generation output (for the 9 major electric utilities) increased at an average rate of 4.4 percent per year, while from 1990 to 1998 it declined overall by 2.5 percent per year due to the economic slowdown in Japan. Additionally, a change in the electricity generation mix from 1990 affected this declining trend. From 1990 to 1998, the share of nuclear increased from 29 percent to 40 percent, while the share of natural gas remained at around 29-30 percent over the same period. Also, newly constructed coal-fired generation plants have contributed to meeting increasing electricity demand. Nuclear and coal-fired units have been installed for base load generation, while natural gas contributes as middle load and peak load generation units. Broad natural gas consumption trends since 1969 are illustrated in Figure 6.

With respect to the city gas sector, from 1980 to 1990 natural gas consumption increased at 9.8 percent per year, while from 1990 to 1998, it increased at 6.5 percent per year. City gas is comprised of LNG, indigenous natural gas, coal, LPG and naphtha. Its changing composition of these components since 1973 is shown in Figure 7.

KOREA

The natural gas industry in Korea has grown very rapidly. Since its first import in 1986, natural gas consumption has increased almost eight fold between 1987 and 1999, with an average annual growth rate of 18.9 percent (see Table 7). This high consumption growth was mainly due to the increase in city gas consumption but also with a significant contribution from power generation use.

At the early stage of natural gas supply, demands of power generation sector constituted most of the market demand. But with the addition of transmission and distribution pipelines, city gas demands expanded very rapidly. The average annual demand growth of city gas use from 1987 to 1999 was 47.4 percent, while that of power generation, coming off a higher base, was 9.9 percent.

Major players in the Korean natural gas industry include: the Korea Gas Corporation (KOGAS), city gas companies, large-volume consumers, and the central government and local governments as regulators. Their identities and main functions are explained briefly below.

Table 7 LNG Consumption in Korea

Year	Power Generation	City Gas	Own Use	Total
	Thousand tons (percentage share)			
1986	45(84.9)	0(0.0)	8(15.1)	53
1987	1,537(94.8)	75(4.6)	9(0.6)	1621
1988	1,905(91.0)	184(8.8)	5(0.2)	2094
1989	1,670(82.4)	349(17.2)	8(0.4)	2027
1990	1,741(74.8)	575(24.7)	12(0.5)	2328
1991	1,800(66.8)	879(32.6)	15(0.6)	2694
1992	2,225(63.1)	1256(35.6)	43(1.2)	3524
1993	2,518(57.2)	1,848(42.0)	37(0.8)	4403
1994	3,329(56.8)	2,451(41.8)	80(1.4)	5860
1995	3,606(50.7)	3,413(47.9)	100(1.4)	7118
1996	4,622(49.1)	4,619(49.1)	175(1.8)	9416
1997	5,377(47.3)	5,770(50.7)	232(2.0)	11,379
1998	4,189(39.3)	6,233(58.5)	222(2.1)	10,646
1999	4,769(36.8)	7,886(60.8)	306(2.4)	12,961
Average Growth Rate (%)	9.9	47.4	34.2	18.9

Source: Korea Energy Economics Institute, Monthly Energy Statistics

KOGAS is the only importer and wholesaler of natural gas at the moment. It owns and operates LNG receiving terminals and nationwide trunk lines. As a monopoly supplier, it supplies natural gas to power generators-currently, the Korea Electric Power Corporation (KEPCO) and Hanwha Energy, an IPP and large-volume consumers with consumption volume over 100,000 m^3/month. It also supplies wholesale gas to retail city gas companies.

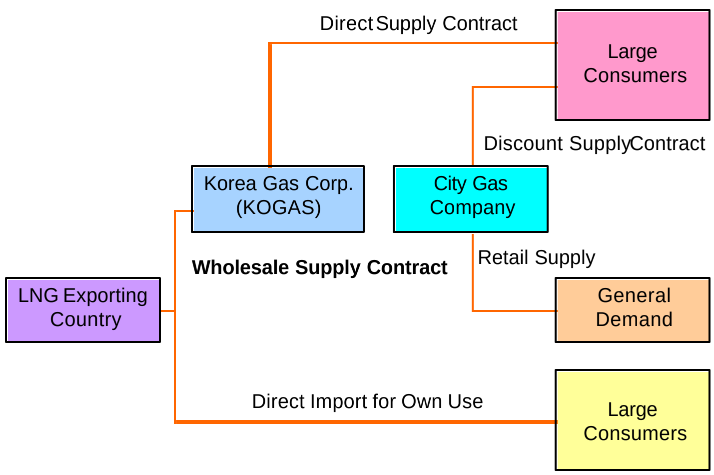
There are twenty-four city gas companies out of thirty-two using LNG as feedstock. They buy wholesale natural gas from KOGAS. They enjoy the status of local monopoly in each company's service territory.

Large-volume consumers are allowed to import natural gas for their own use from 2001, but not to import gas for resale. If necessary for transportation purposes, they can access the KOGAS pipeline network at some access fee. The structure and level of the fee will be decided before the first access by the Pohang Steel Company (POSCO) to the KOGAS grid. POSCO is scheduled to access the KOGAS grid in 2002. Figure 8 shows the structure of the natural gas industry in Korea.

The Gas Industry Division of the Ministry of Commerce, Industry and Energy (MOCIE) approves supply terms and conditions, rates of wholesale gas and direct supply contract of KOGAS with large-volume consumers. The Ministry of Finance and Economy (MOFE) coordinates the levels of gas rates with MOCIE for concerns with inflation. Local governments approve supply terms and conditions and rates of retail gas for the city gas companies within their jurisdiction.

There are three laws that govern the city gas industry where natural gas is used as feedstock: The Law of City Gas Industry; The Law of Petroleum Industry; and The Law of Safety Management of High-Pressure Gases. Also, another special law (that is, one that applies prior to other laws for applicable circumstances) provides rules specifically for enhancing efficiency of the management and the privatising of four major public enterprises, one of which is KOGAS. The Law of City Gas Industry provides the basic framework of the city gas industry, including but not limited to: license-related matters for the importation and supply of gas, construction of gas supply facilities, terms and conditions of gas supply, safety management, and land acquisition.

Figure 8 Korean Natural Gas Industry Structure



The Law of Petroleum Industry governs matters related to importation of natural gas. This law treats natural gas as a kind of petroleum and, accordingly, an importer of natural gas is an importer of petroleum. There was some confusion in the interpretation of two laws, the Law of Petroleum Industry and the Law of City Gas Industry. The problem was that, when POSCO obtained the permission, what did the permission permit POSCO to do? Could POSCO undertake the business of gas supply, that is, could it import natural gas for resale? Or could it import natural gas only for the use within the company? The final interpretation of the laws was that POSCO could import natural gas only for own use with the permission by the Law of Petroleum Industry, but not by the Law of City Gas Industry. For the Law of City Gas Industry permits natural gas importation for the purpose of city gas business, that is, gas importation for resale. This means that POSCO cannot sell the gas that they import.

The Law of Safety Management of High-Pressure Gases rules the safety issues that occur in the process of handling and using high-pressure gases and constructing facilities to supply those gases. The issues related to natural gas supply and consumption in this law are those of the authorities and procedures of activities of the Korea Gas Safety Corporation. The corporation was established by this law and authorised to issue licenses for handling high-pressure gases, and to oversee the safety of gas facilities and appliances and safety activities of gas suppliers, construction contractors and gas consumers.

A special law, the Law of Improvement of Managerial Efficiency and Privatisation of Public Enterprises, was enacted in August 1997 and has been effective since October 1, 1997. The Law is concerned with the managerial efficiency of the four major public enterprises that have attributes of private companies in their operation, early privatisation of the companies, and the way of preventing concentration of market power by equity-holders of the companies. The law takes priority over other laws in ruling matters associated with the governance structure of the companies.

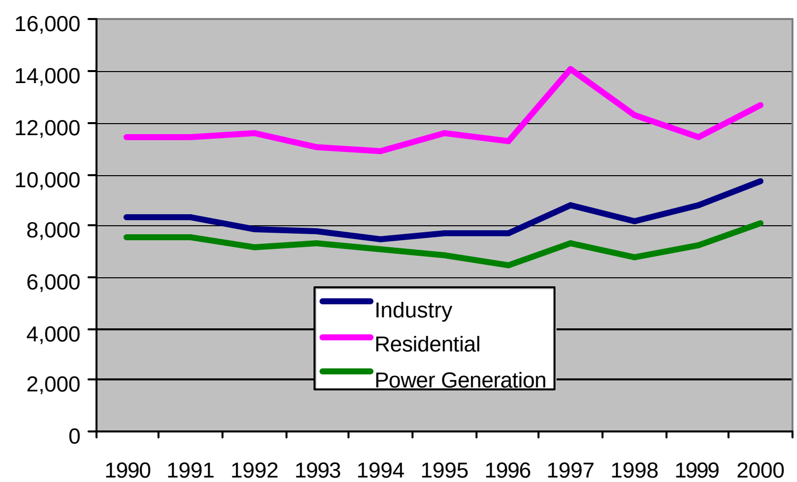
CHINESE TAIPEI

LNG and natural gas comprised 6.7 percent of total primary energy supply in 1999 having risen from 5.6 percent in 1991. Hence, the share of LNG and natural gas in the total energy supply grew only slowly during the 1990s. In 1999, Chinese Taipei domestically produced 14.1 percent of its gas requirements, and imported the balance of 85.9 percent in the form of LNG. These imports were sourced from Malaysia and Indonesia. LNG is primarily used for power generation and also for industrial purposes. Domestic natural gas is used by the residential, commercial and industrial sectors.

There were many reasons for the slow growth of gas consumption during the last 9 years. The main reason was that the price of gas was too high when compared to the price of other fuels. On the other hand, because gas consumption has not increased to a sufficiently high level, potential economies of scale have not been exploited and the price of gas cannot be decreased to a satisfactory level. In Chinese Taipei, the degree of electricity sector deregulation is closely linked to the degree of gas industry deregulation as the gas powered units can adapt very quickly and survive in a competitive electricity environment. Recently, Australia has been trying to promote its LNG to Chinese Taipei as the Chinese Taipei government tries to increase the use of gas for power generation to decrease GHG emissions and meet the requirements of electricity load growth.

Figure 9 Natural Gas Price Trends in Chinese Taipei

NT$/million kcal



Source: APERC Energy Database

The Chinese Taipei government maintains control over domestic wholesale and retail gas prices. Domestic wholesale gas prices are determined by a 'cost-plus' pricing methodology which was approved by the Executive Yuan in 1998. According to this formula, gas prices are reviewed on a monthly basis except those for gas purchased by LDCs which are adjusted biannually. Gas prices reflect the operational needs of the gas utilities, including a return on investment, as well as other social and environmental considerations. The formula also provides pricing discounts of 17 percent and 8.5 percent, respectively, for power generation and some cogeneration plants. The discounts are based on and in comparison to the price for general industrial use. Large private sector consumers are permitted to negotiate prices directly with gas utilities.

The Ministry of Economic Affairs determines retail gas prices according to the Gas Utility Regulations. The retail price considers the operational needs of the gas utilities and consumer welfare, including social equity [Energy Commission, 1998]. In addition, utilities have some recourse of appeal to the Ministry of Economic Affairs for a price review if they can show they cannot operate with a reasonable return at the established price. LNG imported into Chinese Taipei is subject to an import tax of 3 percent and a NT$0.055 per cubic metre excise tax (effective 1 May, 1999). In practice, as far as final consumer prices are concerned, the price of LNG for power generation is the lowest, the price of LNG for the industrial sector being somewhat higher, and the price for the residential sector being the most expensive. Although the Chinese Petroleum Company (CPC) currently monopolises the ownership of existing LNG receiving, storage and transportation facilities, the Chinese Taipei government allows public companies to import LNG and to sell it but under price control.

SUMMARY

- In China, industrial users are the largest and fastest growing consumer of natural gas accounting for around 80 percent of total consumption, while the residential share is around 10 percent. Major policy concerns in the natural gas industry are efficiency improvement and environmental protection.

- The price-setting process involves negotiation between producers, consumers and government with production costs and consumer purchasing power being major determinants of prices. Subsidies are focused on the residential sector. The Chinese government prefers to reduce subsidies but, with consumers having relatively low incomes, this may take some time.

- The Japanese city gas industry is a mature one developed mainly in urban areas since the first LNG cargo in 1969. While there are more than 240 private and public city gas suppliers, four major vertically integrated companies dominate the market with a combined share of 78.5 percent.

- In consideration of the changing environment of the industry, the Gas Utilities Industry Law, the main legislation governing the industry, was recently revised twice, in 1995 and 1999. This has made gas rates for large-volume consumers free of regulation and has streamlined the process of gas rate-setting so long as the rates are being lowered. The gas rate-setting regime has also been revised to accommodate the imminent approval for third-party access.

- Since its first import in the form of LNG in 1986, natural gas consumption in Korea has increased almost eight fold between 1987 and 1999, with an average annual growth rate of 18.9 percent. This high consumption growth was mainly due to the increase in city gas consumption but also with a significant contribution from power generation use.

- Major players in the Korean natural gas industry include: KOGAS, privately owned city gas retail companies, large-volume consumers including the single largest consumer, KEPCO, and central and local government as regulators. Large-volume consumers are permitted to import natural gas for their own use from 2001, and, if necessary for transportation purposes, they will have access to the KOGAS pipeline network at some access fee. As the first large-volume consumer to import natural gas for its own use, POSCO is scheduled to connect to the KOGAS grid in 2002.

- Chinese Taipei imports about 86 percent of its natural gas requirements with the rest being met from indigenous sources. The share of natural gas in total primary energy supply grew rather slowly from 5.6 percent in 1991 to 6.7 percent in 1999. Although the Chinese Petroleum Company currently monopolises ownership of the existing LNG receiving, storage and transportation facilities, the Chinese Taipei government allows public companies to import LNG and to sell it but under price control.

- The Chinese Taipei government maintains control over domestic wholesale and retail gas prices. The pricing method is based on the cost-plus approach. Gas prices are reviewed on a monthly basis except for gas purchased by local distribution companies which is adjusted biannually. Gas prices reflect the operational needs of gas utilities including return on investment as well as other social and environmental considerations. Some discounts are applied to gas for power generation and cogeneration.

OCEANIA

INTRODUCTION

Gas markets in Australia and New Zealand are amongst the most deregulated in the world. They are essentially all privately owned and prices are set via the interplay of the cost of the resource, supply and demand, possible uses and the availability and prices of competing fuels. Although difficult to separately identify, historically there have been cross-subsidies in the sector. Generally, these have been to the benefit of households at the expense of (large) industrial consumers. However, partly due to competition, these have either been completely eliminated or are being phased out.

In both economies, to a greater or lesser degree, gas is a latecomer into incumbent energy markets. As such it has had to compete on price and quality with other fuels. Typically, gas competes with electricity in the household sector, with coal for electricity generation and with heavy fuel oil and distillate in industrial applications. In many instances, therefore, gas use is contestable in both the short and long run.

There are, however, features associated with the gas markets in each of these economies, as well as that of the other APEC economy in the Oceania region, Papua New Guinea. These are reviewed and discussed in turn.

AUSTRALIA

INTRODUCTION

Reticulation of natural gas began successively in the states of Queensland, Victoria and South Australia in 1969, followed by Western Australia in 1971 and finally New South Wales in 1976.

Gas markets in Australia are highly deregulated and highly developed, although this varies widely between the eight states and territories. There is an abundant supply of the resource with a reserve to production ratio of around 91 years. However, the diverse, and in some cases remote, location of gas-fields vis-à-vis demand centres, means that there are a number of essentially independent markets in Australia. This is one of the reasons why there is a wide diversity of penetration and prices between the states and territories.

MARKET STRUCTURE

Legislatively, commercial and energy law in Australia is overseen by a Federal system with considerable autonomy being delegated to State governments. Thus energy endowments, historical development and the policies of state governments means that the states have different energy industry profiles, are differently evolved in terms of deregulation, competition and privatisation and go forward with differing, although generally converging, policies with regard to the development of their energy sectors.

For example, the electricity generation sector in Australia is dominated by coal-fired generation, with gas-fired generation generally remaining comparatively more expensive. Only recently has gas gained some foothold in this sector with a number of plants being promoted in the northeastern state of Queensland, where gas is more competitive and as a pre-requisite for the construction of the pipeline from Papua New Guinea.

The state of Victoria has the most developed gas sector of any of the states and territories, in terms of market mechanisms, deregulation, private ownership, lowest prices and market penetration. Here, historically, while the resource, as elsewhere in Australia, has been privately owned, much of the downstream business including transmission, distribution and retailing has been in government ownership. Deregulation and market reform started in the mid-1990s and has, in many ways, surpassed those in some other states, where both distribution and retailing has been in private ownership for some time. In July 1997 the state-owned Gas and Fuel Corporation was unbundled into three stapled businesses, each comprising a separate distributor and retailer, operating in separate geographical areas. These businesses as well as the transmission pipelines were privatised by May 1999.

DOMESTIC MARKET

Around 3.1 million households (43 percent) and 92,000 commercial and industrial customers are connected to gas. While comprising 97 percent of connections, households consume around 15 percent of demand. Penetration in the household sector ranges from approximately 77 percent [Victoria State Government, 1998] in Victoria to nil in the island state of Tasmania. Connections are currently increasing by around three percent, or 95,000 new connections, per year.

As in many economies, the main growth area is in electricity generation applications, either combined cycle or cogeneration. Queensland is leading the way in the installation of gas-fired power stations. And so it is no surprise that natural gas is projected to be Australia's fastest growing fuel source with its primary fuel share projected to increase from the current 19 percent to 29 percent by 2014-15 [Financial Times Asia Gas Report, May 1999], a growth rate of 4.3 percent per year.

PRICES

The state of Victoria has the lowest gas prices in Australia with average residential prices of around AUS$8.28/GJ and average industrial and commercial prices of around AUS$4.35/GJ. By way of contrast, New South Wales, the largest state on a population basis has prices of around AUS$13.72/GJ and AUS$5.49/GJ, respectively. The highest prices are in the Northern Territory where gas use in these sectors is minimal. Although Victoria has around 24 percent of Australia's total population, the extent of gas penetration and consumption is reflected in the fact that it is the only state whose prices are below the national average of around AUS$9.48/GJ for residential where it has around 68 percent of national demand and amongst the lowest for industrial and commercial at around AUS$4.88/GJ where it has

Table 8 Average Natural Gas Prices 1997-98

	New South Wales	Victoria	Western Australia	South Australia	Northern Territory	Australian Capital Territory	Australia
				AUS$/GJ			
Residential	13.72	8.28	14.78	13.37	20.39	11.64	9.48
Commercial and Industrial	5.49	4.35	3.98	4.35	12.97	9.41	4.88

Source: Adapted from Australian Gas Association (AGA), (2000) and Victoria State Government (1998).

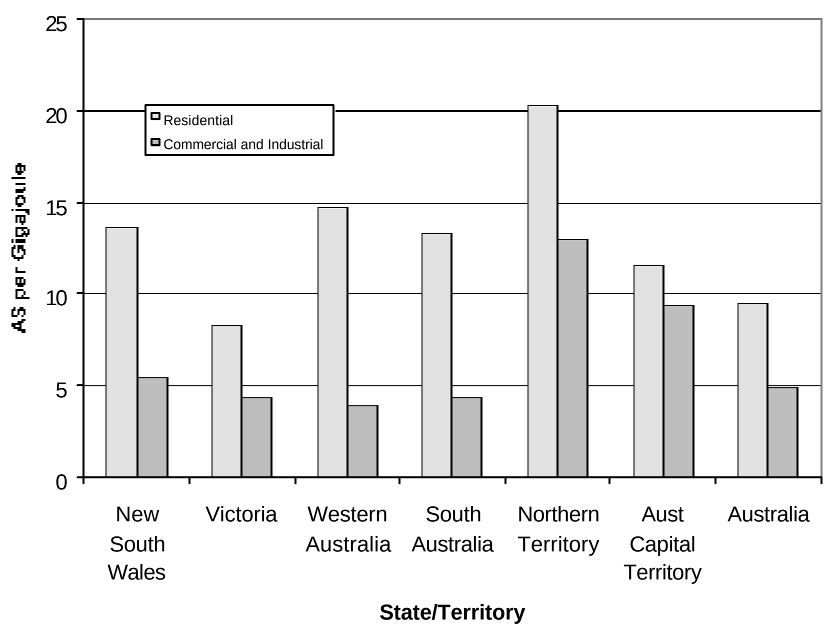
around 30 percent of national demand. Table 8 and Figure 10 give some indication of the range of gas end-use prices in Australia.

Infrastructural developments such as the recently commissioned Eastern Gas Pipeline extending from Longford, Victoria to Horsely Park near Sydney, New South Wales and the proposed Papua New Guinea to Queensland pipeline are expected to introduce more basin to basin competition and thus lead to some convergence in prices.

LNG

Australia is currently the fourth largest LNG exporter in the world with all its LNG exports being sourced from the North-West Shelf of Western Australia. Its exports, which currently go almost entirely to Japan, are dwarfed by those from Indonesia, Algeria and Malaysia but are currently slightly ahead

Figure 10 Australia Average Natural Gas Prices 1997-98



of each of those from Brunei and the major Middle East exporters of Qatar and Abu Dhabi. It is thought that increased Asian demand could treble exports over the next 25 years [Financial Times Asia Gas Report, March 2000]. Ex-plant prices are around AUS$1.90 / GJ [Australian Gas Association]. This higher cost relative to other producers, especially Middle Eastern producers, is mitigated by the lower transportation costs to target markets.

CAPITAL

Australia is regarded by many as having the most robust economy and capital market structures in the South-east Asian region. This state of affairs extends to its energy markets where privatisation and deregulation has seen an infusion of private, often foreign, capital in the last decade. Capital requirements are expected to continue with proposed pipeline infrastructure alone requiring AUS$4,400 million by 2003 [Australian Gas Association, 2000], including the Australian share of the Papua New Guinea-Queensland pipeline and a Gippsland-Tasmania pipeline which will introduce gas to the southern island state.

NEW ZEALAND

MARKET STRUCTURE

The New Zealand gas industry is completely in private ownership. Around 40 percent of consumption is used as feedstock in the economy's chemical methanol plant and other petrochemicals. Electricity generation also uses around 40 percent depending mainly on rainfall into the economy's hydro-dominated generation system, the operational availability of gas-fired stations (which generally operate in base load but after hydro) and the availability of contracted gas. The remainder is reticulated with industry consuming around 80 percent, the commercial sector and residential sectors 10 percent each. Maui Development Ltd and the Natural Gas Corporation together own the transmission network. There are five distributors and six retailers.

The economy has a reserves-to-production ratio of around twelve years. Gas is neither directly exported nor imported and so production and consumption can be viewed from a completely domestic perspective. While the outlook for new resources has at times not looked good, a number of recent discoveries in relatively easy to develop regions have considerably improved the situation somewhat. Due to the small size of the gas market and the uneconomic nature of exports and imports, the industry lacks both the breadth and depth that is apparent in other economies.

The New Zealand Government operates a "light handed" regulatory regime in the energy sector including a disclosure regime for the monopoly and access aspects associated with transmission and distribution. Perceived market dominance is occasionally a significant issue in the supply of gas itself and this had led to some interesting situations when major participants have added to their portfolio by way of discovery where this may have increased market dominance. Market dominance issues may also prevent mergers or takeovers in any segment of the industry. The regulatory situation for the gas industry is less well evolved than that for the electricity sector with the Government signalling that improving shortcomings in the latter is of a higher priority. Given the above, the gas market would appear to be operating reasonably well.

PRICING

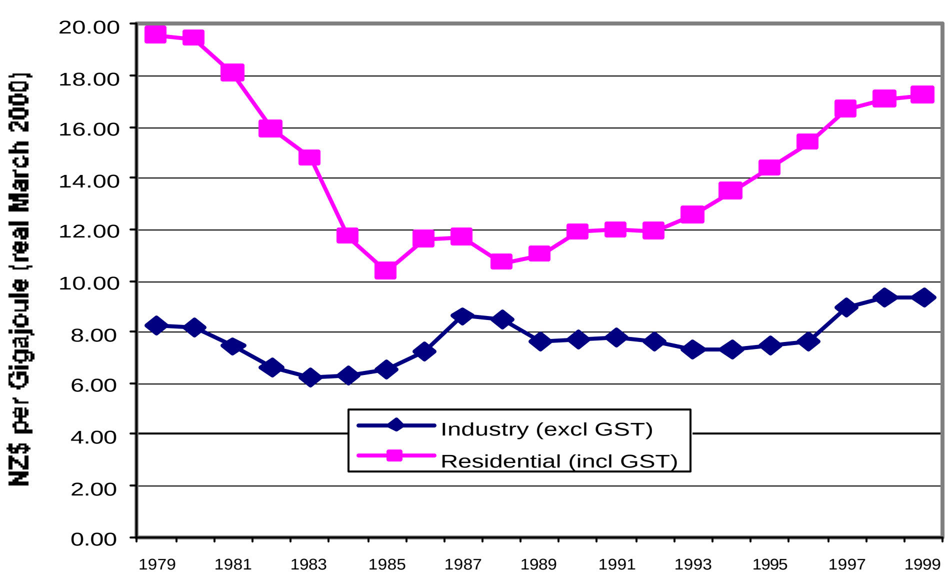
As with other developed gas sectors, transmission has been unbundled from downstream activities although, in contrast to the electricity sector, legal separation has not been required of the single owner of the transmission pipelines at this time. Tariffs to final consumers are required to unbundle distribution and energy charges although, again, the distributor and the gas retailer can be the same entity. Third party access to pipelines does exist. As in many economies, competition is stronger for larger consumers than for smaller ones such as residential where the main competition issue is gas gaining a fuel share in electricity-only households.

The latter is rather problematic as gas prices have recently been increasing faster than electricity prices and dual-energy households have to pay line charges for both gas and electricity. Currently around 10-12 percent of households receive reticulated gas with the potential being considerably higher as many unconnected households have distribution lines passing along their streets.

At the wholesale level, the New Zealand gas industry remains dominated by the Maui Take-or-Pay contract that was enacted into law in 1973 when the Government still had significant ownership of the industry. This contract is not subject to recourse but the world-class Maui field and the contract are expected to expire by the end of the decade (2010). Supply contracts for other producing fields are generally on a fairly long-term basis with explorers generally preferring to develop fields only when sufficient economic forward contracts have been obtained. In general, the spot market is thin with some secondary trading downstream of the wellhead. There is considerable horizontal integration in the New Zealand energy sector with companies owning gas and electricity businesses as well as possibly being involved in electricity generation and so there can be some flexibility as to how a company manages its gas offtakes.

The pricing of gas is essentially market-based. As a latecomer to the fuel scene, especially in the residential sector, gas has generally had to compete (on price) with other incumbent fuels. Thus gas competes with electricity in the residential sector, with most other fuels in the industrial sector and to a limited degree with coal for electricity generation where, in recent years, it has gained the superior position as witnessed by the commissioning of two large combined cycle stations.

Figure 11 New Zealand Natural Gas Prices 1979-99



Source: New Zealand Energy Data File, January 2000

There are no government subsidies in the gas industry. Historically, some larger consumers in the industrial and commercial sectors have tended to cross-subsidise residential consumers. These cross-subsidies are being gradually removed with residential prices having risen faster than industrial prices in the last decade. This (partly) explains the divergence in prices in the last decade shown in Figure 11. Occasionally retailers may provide inducements to gain market entry (to electricity-only households) or market share (in the case of industrial and commercial consumers).

It is argued that the deregulated nature of the market and the exploration regime encourages explorers and developers to explore and bring on supply in a timely manner. New Zealand has a comparatively transparent and robust foreign investment regime that has seen foreign involvement in all exploration activities in recent years. Recent exploration successes would tend to corroborate both the effectiveness of the exploration and foreign investment regimes. This activity has often involved partnerships of domestic and small foreign, so-called "independent" companies and this can be expected to continue into the future. Given the uneconomic nature of imports, failure of the regime could well see the price of gas rise in both real terms and relative to other fuels.

No major infrastructural developments are required other than that needed to bring new discoveries such as the Westech consortium's on-shore east coast discovery to market. In contrast, the Kupe off-shore field has remained undeveloped for many years, as it is a relatively high cost field.

PAPUA NEW GUINEA

Papua New Guinea is well endowed with natural gas resources with an estimated 357 mtoe (15,250 PJ or 14 tcf) of proven reserves [Papua New Guinea Government, 1996]. Although some of these resources were first proven over 40 years ago with much of it proven in the 1980s, to date, there has been no significant use of the resource. A 2,600 km [ACIL, 1999] pipeline is proposed by a partnership between Australian Gas Light and Malaysia's Petronas Group for Chevron Overseas Petroleum to export gas from the Kutubu field in the Papua New Guinea highlands, a field that has estimated reserves of 2180 PJ, to the state of Queensland in Australia. The pipeline required approximately 120 PJ per annum [Financial Times Asia Gas Report, September 1998 and August 1999] of pre-commitments to become viable and this has come by way of a number of contracts which have been signed by power generators and major industrial plants. Overall, Queensland expects its use of gas to quadruple from 70 PJ to 280 PJ per annum by 2006 [Papua New Guinea Gas fact sheet, 1999] and much of the new supply will come from this source. The gas is being sold on a netback basis.

In Papua New Guinea itself, other projects being investigated include an LNG plant, a methanol plant and some electricity generation for the main population centre of Port Moresby and environs. There is currently no reticulated gas supply in Papua New Guinea. Some households use bottled gas. Significant developments are heavily dependent on foreign capital.

SUMMARY

- Gas markets in Australia and New Zealand are amongst the most deregulated in the world. They are essentially all privately owned and prices are set via the interplay of the cost of the resource, transport costs, supply and demand, possible uses and the availability and prices of competing fuels.

- Although difficult to separately identify, historically there have been cross-subsidies in the sector. Due, partly, to competitive pressures, these have either been completely eliminated or are being phased out.

- In both economies, to a greater or lesser degree, gas is a latecomer into incumbent energy markets. As such it has had to compete on price and quality with other fuels.

- In Australia, there is a wide diversity of penetration and prices between the states and territories. This is partly explained by the geographical isolation of demand centres and supply sources. This also means that although competition is possible and encouraged, it is not widespread. In the main consuming regions, the average household price (1997-98) ranges from AUS$8.28/GJ in Victoria to AUS$14.78 in Western Australia with the average combined industrial and commercial average price ranging from AUS$3.98/GJ in Western Australia to AUS$5.49/GJ in New South Wales.

- New Zealand has a small but well-developed reticulated gas market. Deregulation and market reforms in the 1990s have seen the gradual removal of cross-subsidies that have existed with household prices having risen faster than prices for industry in the last decade.

- Australian and New Zealand end-use gas prices are generally higher than those of the other two major APEC consumers of reticulated gas, the U.S. and Canada. This is currently not the case given the state of gas markets in North America.

CHAPTER 5

CASE STUDIES

KOREA

WHOLESALE PRICE

PRICE STRUCTURE

The wholesale price charged by KOGAS consists of two components, the feedstock cost and supply costs. There are seven items that constitute the feedstock cost: (i) the import price, (ii) an import handling charge, (iii) an import tariff, (iv) a special excise tax, (v) losses, (vi) an import surcharge and, (vii) a safety management surcharge. Among the items, the import surcharge and the safety management surcharge are applied only to city gas customers (see Table 9). Since the LNG import price is indexed to the oil price, to reflect fluctuations in the import price and in the exchange rate the feedstock cost is adjusted on a monthly basis for power generation customers. In contrast, to avoid frequent price changes, the feedstock cost adjustment is considered on a quarterly basis for city gas customers and implemented only if the change exceeds ±3 percent.

The wholesale supply cost is calculated and adjusted annually, and consists of the receiving terminal costs and transportation costs. For power generation customers, three seasonally varying rates are applied: winter, summer, and other seasons. For city gas customers, supply costs differ by end-user type. There are five classes of end-uses for city gas customers: residential/heating (includes cooking, heating, business office heating), cooling, commercial, industrial, building co-generation and district heating. For each end-use type, a uniform rate is applied throughout the year, except for the building co-generation and district heating use, which has three different seasonal rates.

Table 9 and Table 10 show the figures of the components that constitute feedstock costs and supply costs, respectively, as of January 1, 2000. In order to diversify energy sources and to rapidly increase the penetration of natural gas, feedstock and supply costs were kept low, especially in the early years of LNG imports. Although direct government subsidies for natural gas were absent, natural gas has received preferential tax treatment. The import tariff on LNG is only 1 percent whereas that on crude oil and LPG is 5 percent. Other charges levied on alternative fuels, such as the import surcharge, the special excise tax and the safety management surcharge, were not introduced to LNG until after 1994. Moreover, the revenue from the import surcharge was set aside as the 'petroleum business fund' and loaned out for the construction of the natural gas pipeline network at a low interest rate. This also contributed, along with other measures, towards keeping the supply cost of natural gas low compared to other fuels.

Table 9 Wholesale Feedstock Cost Components(1)

Components	Electricity	City Gas	Remarks
	won/m³		
Import Price	184.24		Contract Price
Import Handling Charge	0.27		Importing Incidental Expenses
Import Tariff	1.87		1% of CIF
Special Excise Tax	32.31		Flat amount of 40 won/kg
Loss	2.04		0.9% of CIF Import Price and Import Handling Charge
Import Surcharge	-	5.58	Flat mount of 6,908won/ton
Safety Mgt Surcharge	-	3.9	Flat amount of 3.90 won/m^3
Total Feedstock Cost	220.73(2)	230.21(2)	

Notes: (1) As of January 1, 2000.
(2) For these figures, an adjustment is made in the first quarter of every year to allow for import price changes that have occurred, but not reflected during the period of the past year. In 2000, a credit of 8.61 won/m^3 was due from the 1999 pricing. Hence, actual feedstock costs for power generation and city gas applied were 212.12 won/m^3 and 221.60 won/m^3, respectively, by subtracting the amount of credit due from these figures.

Table 10 Wholesale Supply Costs (1)

End-User Class		Winter(1)	Summer(1)	Rest	Remarks
Power generation		53.72	25.56	39.64	
City Gas(2)	Residential/Heating	107.76			
	Cooling	-			May – Sep
	Commercial	59.96			
	Industrial	27.12			
	Building Co-generation & District Heating	75.18	13.23	42.6	

Notes: (1) As of January 1, 2000.
(2) Average supply cost for city gas customers is 91.64 won/m^3.

HISTORY OF SUPPLY COST CHANGES

The supply costs were first announced on February 2, 1987. At the time, KOGAS' supply costs were determined at a level that enabled the recovery of its total costs. But in order to take advantage of the economies of scale, demand creation was actively sought through setting (i) a low price, (ii) the period of assessing supply costs at three years (from 1987 to 1989) and, (iii) the return on equity at zero. The total supply costs were allocated between power generation and city gas sectors on the premise that the total price for city gas consumption equals the price of city gas that used LPG-air as a feedstock. The balance of total costs was allocated to the power generation sector. That is, the supply cost for city gas customers was set at the existing LPG-Air end-user price less a retail margin and feedstock cost, while the rest of the required revenue was made up by the supply cost charged to power generation customers.

The supply cost assessment period was revised three months later, however, to five years from three years in order to gradually adjust the city gas rate to a competitive level in relation to other fuels. All the benefits of the lower supply cost were applied to the city gas rate only. Shortly after, as the competitiveness of city gas was weakened by an average of 10 percent price reduction in domestic petroleum products, the government further reduced the city gas supply cost to restore the price competitiveness of city gas. In December 1987, the government revised the method of supply cost allocation to the average cost assessment without subdividing the costs by usage category. The supply costs for both city gas and power generation customers were set at the total average supply cost, 40.89 won/m^3, reducing the city gas wholesale supply cost by 17.09 percent.

The two-time price reductions on domestic petroleum products in 1988 diminished the merits of using natural gas again in terms of price competitiveness. In addition, the policy to reduce pollution restricting the use of liquid fuels in the metropolitan Seoul area from September 1988 raised the need to reduce the rate charged for city gas. In consideration of the cost curtailment in power generation due to the two price reductions in petroleum products, the city gas supply cost was lowered by 22.72 won/m^3 while raising the supply cost for power generation by 7.05 won/m^3. Additionally in January 1989, the supply cost was reduced by about 5 percent owing to the change in the calorific content of natural gas from 11,000 kcal/m^3 to 10,500 kcal/m^3.

As can be seen from the underlying reasons for the supply cost changes until this point in time, the method of wholesale supply cost assessment explicitly permitted cross-subsidies[21]. It was decided that keeping the price of city gas competitive with other fuels was more important than keeping gas prices in line with actual costs. Setting aside the question of cross-subsidy being actually in existence, the practice of setting the supply cost for city gas customers in consideration of other fuel prices, but apart from reflecting their induced costs, evidences the fact that cross-subsidy was not taken seriously until then.

As the demand for natural gas from city gas usage rose sharply, the supply costs of city gas companies were curtailed and their financial strength improved. This led to the adoption of corrective measures for the distortions in wholesale rates. The adjustment of June 1989 addressed the cross-subsidy problems. It aimed to alleviate the burden borne by the power generation sector for the costs that ought to be borne by the city gas sector. Thus, the supply cost for power generation was lowered and that for city gas usage was raised to more accurately reflect the costs for both sectors.

Following the expiration of the cost assessment period (1987-1991), supply costs were reassessed from July 1992. The support for city gas usage was drastically reduced, as the supply costs were stabilised by the sharp rise in natural gas consumption. The supply cost assessment period was returned back to 3 years (1992-1994) and the rate of return on equity was set at 10 percent after tax. In addition, an 'investment resource' item was included in the rate base in consideration of KOGAS' ability to procure funds relative to investment costs during a cost assessment period, leading to an increase in the gas rate.

As city gas consumption expanded rapidly, the need to modulate seasonal loads had arisen and a seasonally differentiated supply cost system was introduced in January 1994 for power generation customers. But the average level of supply costs for power generation and city gas sectors was pegged to the previous level and the problem of cross-subsidy still remained.

In 1998, action was taken to better reflect the costs attributable to the load factor differences between power generation and city gas customers. At the same time, the power generation sector was exempted from the investment resources levy. The supply cost thus adjusted, partially corrected the cross-subsidy problem. In October 1999, a further adjustment was made. This move reduced the supply cost for the power generation customers by 4.44 won/m^3. For city gas customers, the supply cost had to be raised by 13.33 won/m^3 by the move, but in order to suppress a price hike, the supply cost was held unchanged by eliminating the same amount of investment resources levy from the rate base.

SUPPLY COST ALLOCATION METHOD

At present, the assessment of supply costs is based on the recovery of average accounting costs, and is carried out by the following steps. First, the total costs to be recovered are classified by the five functional cost pools of unloading, storage, re-gasification/injection, pipelines, and valve stations. The second step is to allocate each functional cost between the power generation and city gas sectors based on their average consumption patterns. The cost allocation factors for each function are as follows:

(i) unloading costs - annual consumption volume

(ii) storage - necessary storage volume to support each consumption sector

(iii) re-gasification/injection - maximum monthly injected volume

(iv) pipelines - separate assets by power generation sector exclusive and city gas sector exclusive (common costs are divided by reflecting load factors: monthly average consumption / load factor)

(v) valve stations - the same as for pipelines

The cost allocation method used by KOGAS has improved a great deal by better attributing the costs incurred by each sector. Accordingly, the cross-subsidy problem has been greatly alleviated thanks to the elimination of overt cost-shifting practices and corrective measures taken to reflect the attributable costs.

However, cross-subsidies may still be present, if the term is used loosely as applied to any case when prices do not reflect the supply cost difference - in this sense, it is the appropriateness of cost allocation that becomes the relevant criteria for discerning cross-subsidisation, rather than the economic definition. It is true that objective cost allocation criteria on which all can agree are absent and they can be arbitrary, but even with the current allocation method accepted as reasonable, it falls short of reflecting attributable costs to an extent that is satisfactory. Specifically, in that it failed to capture some hidden cost factors such as avoided storage costs and differences in service contents.

Due to the demand patterns of power generation customers, city gas customers are saving a great deal in terms of the storage cost. Without the power generation demand, more storage tanks would have to be built to accommodate the city gas demand pattern. The costs of storage tanks that are avoided should be properly reflected in the pricing. Also, during the peak season there have been occurrences where power generation customers were asked to stop using natural gas temporarily in order to relieve pipeline capacity/gas shortage problems. In effect, the supply service to power generation is interruptible, while to city gas customers is a firm service. But this difference in service content is also not appropriately reflected in the pricing.

RETAIL PRICE

PRICE STRUCTURE

At the city gas company level, the retail price consists of feedstock costs and supply costs. The former is the wholesale price (city gate price) charged by KOGAS to city gas companies. The import price of LNG is adjusted quarterly according to changes in the foreign exchange rate and the LNG price. A 10 percent value-added tax (VAT) is added to the supply costs of retail companies. Rate-making is based on cost-plus methodology with a 10 percent after-tax rate of return on equity capital. Each local government approves the city gas price of the city gas company/companies within its jurisdiction. If more than one city gas company operates within a jurisdiction, end-use prices, in principle, are determined as an average of the supply costs of those companies. While, in principle, rate revisions are undertaken every year, the local government has some flexibility in revising the rate within a three-year period considering such economic circumstances as the stability of gas rates and the general price level.

Rates are differentiated by end-use type and determined by local governments. There are nine types of end-use in the case of the metropolitan Seoul area as follows, although the categorisation may be different across localities.

- Residential Cooking/Residential Heating
- Commercial I/Commercial II
- Building Heating/Building Cooling
- Industrial
- Building Cogeneration
- District Heating

There are no seasonal differential rates. But, since the load factor of the city gas consumers is much lower than the load of power generation customers, the turn-down ratio is much higher in the city gas sector. It is therefore difficult to maintain supply and demand balances, especially in the winter season, KOGAS and city gas companies signed a load adjustment contract which provides some incentives to manage loads on the part of the city gas companies. The agreement was reached in February 1996 after a long debate between the parties. It stipulates that if the offtakes by a city gas company are above or below the allowance of ±10 percent of contracted amount, it will pay a penalty calculated as the divergence from the allowance times 2 percent of the KOGAS supply price. The penalty period has changed in frequency: there was no penalty during 1996; the penalty was assessed on a quarterly basis in 1997; and from 1998 the penalty has been assessed on a monthly basis. However, in times of extraordinary weather conditions, some allowance can be negotiated. Currently, weather conditions are regarded as extraordinary depending on whether it is warmer or colder by more than the standard deviation of temperature during the time period of the year in question.

RATE DESIGN ISSUES

As mentioned above, in the case of metropolitan Seoul area, some averaged supply costs are applied for ratemaking purposes. Specifically, there are five retail companies who supply city gas to customers in this area, four of which supply Seoul and its vicinities. In ratemaking, the five companies are regarded as one big company by the regulator (the Mayor of Seoul), that is, the unit supply cost is calculated by dividing the sum of revenue requirements of the five companies by the sum of expected supply volumes. In this way, a retail company with lower supply costs than average can make profits and this can work as an incentive for efficiency. But this way of business also aggravates the financial health of a company who has suffered losses by neglecting the different end-user composition across the companies, although the companies may break even as a whole.

Looking at the allowed retail margins (supply costs), there appears a wide range of variations among end-uses (See Table 11). Low margins are allowed to residential heating and building cooling, whereas high margins are applied to residential cooking and commercial I uses. In particular, the gas for district heating is allowed the lowest margin at 7.72 won/m^3, less than half of the margin for industrial use.

However, since the three types of end-uses, namely, residential heating, building heating and district heating, constitute more than 80 percent of total city gas consumption and their turn-down ratios are high, there is doubt that they may not pay their fair share of supply costs. Also, although the volume of the district heating consumption is large, its load pattern is similar to that of the residential heating use-winter-high-and-summer-low. This implies that the district heating gas may be charged too low a price. More specifically, while it is an empirical question, there might be cross-subsidies from other end-uses to the three.

Table 11 City Gas Prices and Retail Margins in Korea

		Consumer Price	Wholesale Price	Retail Margins
			won/m^3	
Residential Cooking		470.34	365.13	105.21
Residential Heating		412.08	365.13	46.95
Commercial I		406.45	305.61	100.84
Commercial II		362.83	305.61	57.22
Building Heating		422.95	365.13	57.82
Building Cooling		198.18	161.59	36.59
Industrial		296.84	278.5	18.34
Building Cogeneration	Winter	366.13	327.83	38.3
	Summer	293.51	255.21	38.3
	Others	328.5	290.2	38.3
District Heating	Winter	335.55	327.83	7.72
	Summer	262.93	255.21	7.72
	Others	297.92	290.2	7.72

Note: 1) As of September 1, 2000.
2) Commercial II includes sauna, trash incineration, health club, etc.
3) Winter consists of January, February, March, and December; summer May, June, July, and August; and others April, September, October, and November.

Another important feature of the city gas prices in Korea is that there have been cross-subsidies to gas for commercial building cooling use from other types of end-uses (See Figure 12). For certain periods of time, building cooling customers have paid even less than the gas cost.[22] This implies that they have been charged negative supply costs. In other words, they have been more than cross-subsidised. Neither the retail companies lose any money nor do the wholesale supplier owing to this practice, since all the gas costs and supply costs are passed through to the consumers. The retail margin for this end-use has virtually been fixed at the level around 40 won/m^3 despite the changing market environment. It may be argued that the marginal cost of gas for building cooling during the period from May to September is around 40 won/m^3, assuming that there is no change in fixed assets. However, other types of large consumers such as industrial users and district heating users are charged much lower margins than building cooling customers, which means that the 40 won/m^3 level of supply cost may not be the marginal cost of gas for off-peak period.

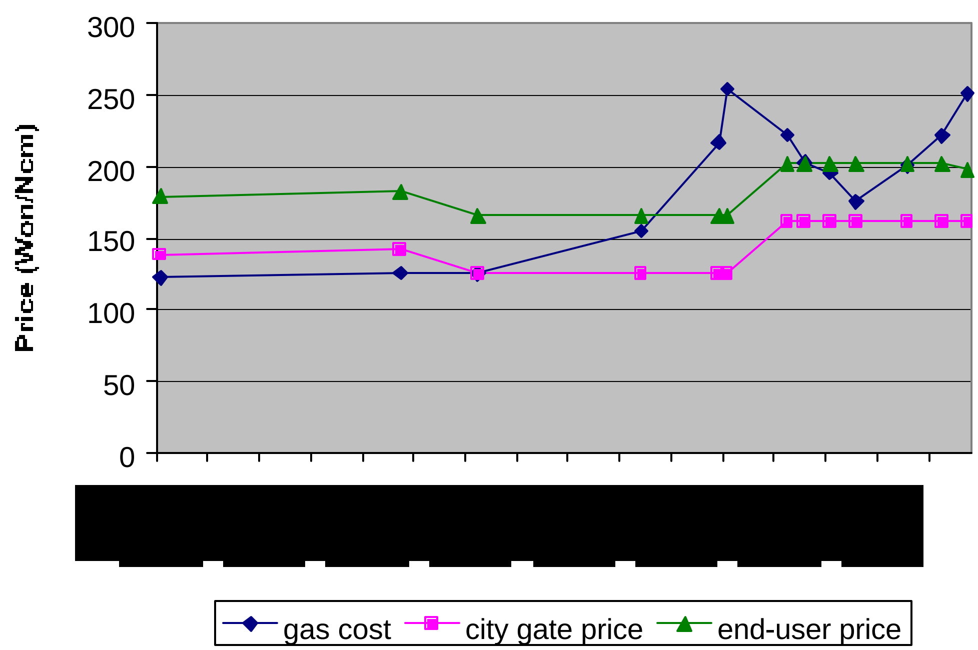
The purposes of this practice are to save the construction cost of gas storage facilities by smoothing out the seasonal load profile; to reduce unit supply cost resulting from the realisation of economies of scale; and to improve air quality by substituting natural gas for other fossil fuels. However, the price signal at the wholesale level, which often reflects policy objectives of the central government for the natural gas market, has often not reached final consumers. For the rate approval jurisdictions are dichotomised between wholesale and retail and the retail supply cost structure differs by localities according to the development stage of local gas markets and the local government's policy concerns.

EVALUATION

Although cross-subsidies distort price signals and reduce efficiency in resource allocation, it is not obvious that they are necessarily bad practice. In retrospect, the Korean experience of fuel substitution by accelerating natural gas use at the early stages of LNG may have been prudent policy.

Coming out of the two oil shocks of the 1970s, the Korean government felt diversification of energy sources was imperative to continued and stable economic growth. Cross-subsidies and indirect subsidies for LNG consumption through preferential tax treatment as a part of diversification policy enabled

Figure 12 City Gas Price for Building Cooling in Korea



Note: This price is applied in the metropolitan Seoul area from May to September. VAT is excluded.

Source: Korea City Gas Association (1999), Yearbook of City Gas Business; and Korea Energy Economics Institute, internal data.

the rapid penetration of LNG use. As a result, in the 14 years since LNG was introduced, 58.4 percent of national penetration rate was achieved in 1999 (77.6 percent for metropolitan Seoul and vicinities). In view of increasing environmental concerns, the promotion of LNG to rapidly achieve a substantial market base can be seen as having been desirable, since natural gas is relatively environmentally friendly. In this respect, it is hard to make a value judgement on the undesirability of cross-subsidies at the (early) stages of network building and of demand promotion to diversify energy sources and to achieve economies of scale as in the Korean experience.[23]

Nonetheless, the Korean cross-subsidies policy in the natural gas market was not without problems. Besides the obvious problem of causing price distortions, it has had the result of running counter to the nation's income redistribution policy. That is, it had the effect of helping the rich at the expense of the poor, since the residential consumers of natural gas who were subsidised are a relatively well-off group. Since electricity is consumed by all people, the cross-subsidisation from the power generation sector to the city gas sector meant that the population at large were helping out a relatively well-off subgroup.

SUMMARY

- The natural gas wholesale price consists of the feedstock cost and supply costs. The feedstock cost includes the import price, an import handling charge, an import tariff, a special excise tax, losses, an import surcharge, and a safety management surcharge. The sum of wholesale feedstock cost and supply costs plus the retail supply costs of local distribution companies constitutes the final consumer price.

- The LNG feedstock cost is adjusted on a monthly basis for power generation customers to reflect fluctuations in the import price and in the foreign exchange rate, while, to avoid frequent price changes, it is considered on a quarterly basis for city gas customers and implemented only if the change exceeds ±3 percent.

- The assessment of supply costs is based on the recovery of average accounting costs both in the wholesale sector and the retail sector. An after-tax 10 percent rate of return on equity is applied.

- The cost allocation method adopted by KOGAS has improved a great deal in attributing the costs incurred by each sector: electricity generation and city gas. Accordingly, the cross-subsidy problem between electricity generators and city gas consumers has been greatly alleviated due to the elimination of overt cost-shifting practices and corrective measures taken to reflect attributable costs.

- In order to improve the penetration of natural gas, low city gas price and subsidy programmes have been adopted particularly for the gas for space cooling of commercial buildings and for district heating.

- Although cross-subsidies distort price signals and reduce efficiency in resource allocation, it is hard to deny that they contributed to the rapid expansion of natural gas utilisation, cost savings in storage facility construction, unit cost reduction through economies of scale, and the resultant welfare gains in Korea.

JAPAN

CITY GAS RATE SETTING

The Gas Utilities Industries Law stipulates three principles concerning the city gas rate setting to provide a reasonable gas price that protects small consumers from monopoly power. The principles are as follows:

1. Price should be determined according to the cost required for providing service,

2. Price should be based on a fair rate of return, and

3. Customers should be offered fair prices taking into consideration different usage patterns and service conditions.

To be more concrete, the first principle indicates that reasonable city gas pricing can be attained when the following two conditions are satisfied.

- Total revenue from gas sales = Total cost for gas supply, and

- City gas price per user = Supply cost per user.

This means that city gas companies should offer gas prices that cover total costs while providing adequate, reliable and high quality service to its customers.

The second principle indicates that determining the rate of return should be based on appropriate management costs and revenues required for sound future development of the company. The third principle means that customers should be offered prices reflecting the difference in services and load characteristics. In other words, the third principle refers to the basis of gas pricing as a whole, meaning that fair gas prices can only be set when offered gas prices appropriately reflect the cost differences caused by the difference in service conditions.

CITY GAS RATE SETTING PROCESS

City gas companies work through the following three-step cost allocation process before filing a gas rate application to the Ministry of Economy , Trade and Industry (METI).[24] As Figure 13 shows, firstly, city gas companies estimate the total cost for supply, secondly, they allocate the total cost according to its function, and thirdly, they make the gas rate menu by classifying it according to type of customers and type of demand. This gas rate schedule is submitted to the Minister of METI for consideration. After consulting with experts, the Minister usually approves the schedule subject to the condition that the new rates will not significantly affect the price level of the overall economy.

ESTIMATING TOTAL COST

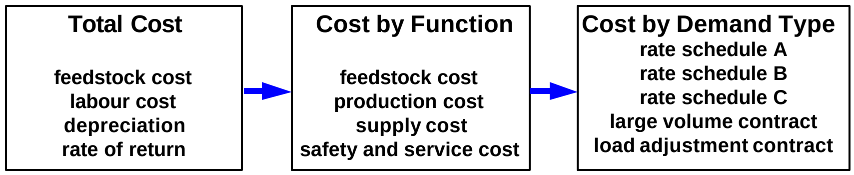
The total cost is estimated by taking the following steps. First, total demand volume for the coming 1-3 years is estimated, then, it is assigned to different tariff categories. Also, some figures (volumes) required for functional cost allocation, such as volume at peak demand, maximum flow per hour and number of households requiring metering, are estimated as well. Secondly, based upon estimated demand volume, some plans regarding production, feedstock procurement, facility construction, financing and labour employment are made. Thirdly, based upon these plans, costs are estimated in the following categories: feedstock cost, labour cost, cost for maintenance, tax, safety management cost and rate of return.

FUNCTIONAL COST ALLOCATION

In order to appropriately allocate the estimated total cost to the different tariffs, the estimated total cost is classified into four functional areas reflecting the origin of the costs. These costs are (1) the feedstock cost, that is, the cost of the natural gas and charges for water and electricity use, (2) the production cost, including facility construction and O&M, (3) the supply cost covering pipeline construction and O&M, (4) safety and service costs such as the labour cost for metering and safety management.

CREATION OF GAS RATE MENU

Figure 13 Cost Allocation Process



City gas companies provide a gas rate menu with categories based on the pattern of use and volume (Table 12).

The rating components applied to customers under demand categories Rate Schedule A, B and C comprise two: (1) a basic (fixed) charge and (2) an incremental charge based on volume.

Table 12 Classification of Rate Menu by Type of Customers

Category	Volume	Type of customers
Rate Schedule A	From 0 m^3 to 25m^3 per month	Residential users mainly on cooking demand
Rate Schedule B	From 25m^3 to 500 m^3 per month	Residential and commercial users on heating and hot water
Rate Schedule C	More than 500 m^3	Commercial users
Large Volume Contract	There are basically 4 categories classified by the type of use: (1) small air conditioner user, (2) summer air conditioner user, (3) air conditioner user and (4) time of use.	

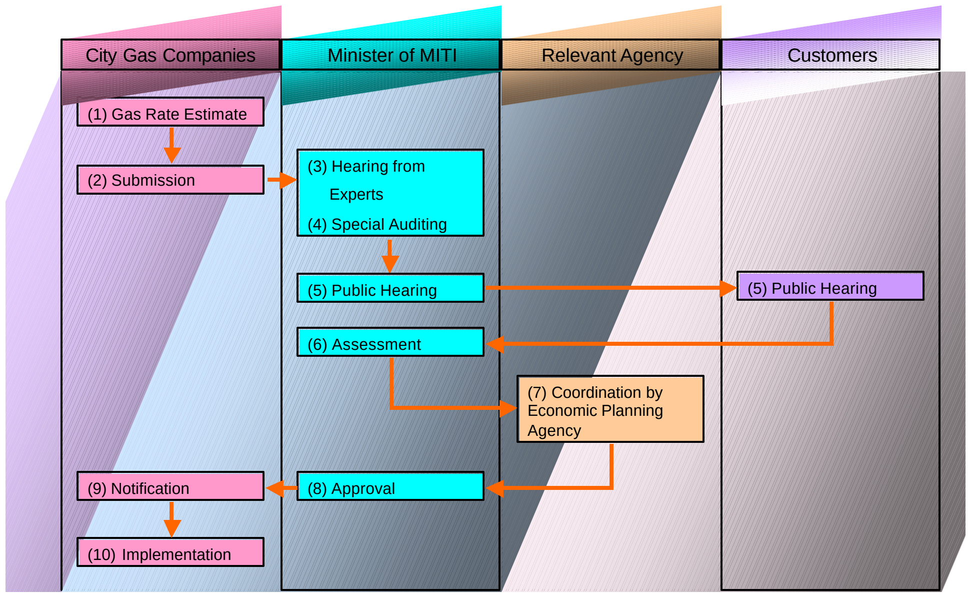
RATE APPROVAL PROCESS

The proposed gas rate menu is submitted to the Minister of METI for approval. To examine whether the submitted gas rate schedule reasonably reflects costs, the Minister meets with the city gas company, and if necessary, a special accounting auditing is also held. Then in order to examine the submitted gas rate in as fair a manner as possible, as required by Article 47 of the Gas Utilities Industry Law, METI holds a public hearing where scholars and participants from interested parties give their opinions on the submitted gas rate and its terms and conditions. If the gas rate meets the criterion stipulated in Article 17 of the Gas Utilities Industry Law, METI gives its approval. In the case of large gas companies, since the impact of gas prices has a large impact on consumer prices, the Agency of Economy and Planning coordinates the gas rate level by holding a meeting with scholars and representatives from consumer groups. In this way, as Figure 14 shows, gas rates are approved after a series of assessments.

CHANGES IN ASSESSMENT CRITERIA FOR CITY GAS SUPPLY COSTS

A brief description of the supply cost assessment criteria for city gas companies is presented. Between 1957 and 1972, the Japanese government allowed a fixed rate of return on common equity. An 8.22 percent of rate of return was allowed for corporate bond-issuing city gas companies, and 8.62 percent for other city gas companies. The rate of return on equity was set at 7.7 percent. It was based on

Figure 14 The City Gas Rate Approval Process



the time deposit interest rate of 6 percent. After subtracting 5 percent tax on interest, the net interest rate was taken to be 5.7 percent. To this 5.7 percent rate of interest, a risk premium of 2 percent was added, making the return on equity 7.7 percent. For companies issuing corporate bond, a 9 percent of return on debt was applied, and for others 10 percent. The rate of return was computed by the weighted average of returns on equity and debt using a standard fixed ratio of equity to debt at 60:40, resulting in 8.22 percent for bond-issuing companies and 8.62 percent for others.

Between 1972 and 1995, the standard fixed ratio of equity to debt was changed from 60:40 to 30:70, reflecting the actual financial structure of city gas companies. The return on equity (8 percent) was computed by a simple arithmetic average of the following four factors: one-year time deposit rate (5.5 percent), the dividend yield to preferred stockholders (6.858 percent), the after-tax return on equity of all industries excluding the city gas sector for the five years from 1966 to 1970 (11.69 percent), and optimal dividend yield (11 percent). Until 1988, the return on equity for major city gas companies was 8 percent, and for smaller companies 8.22 percent. In 1988, the return on equity for major city gas companies was reduced to 7.2 percent and for smaller companies to 7.82 percent because of lower interest rates.

Since 1995, the return on equity has been set at the appropriately weighted 5-year average of 'the average returns on equity of all industries excluding city gas industry' as the upper limit, and 'the interest rate of public corporate bonds' as the lower limit. The return on debt is set at the average interest rate on debt of all city gas companies for the preceding year. The standard fixed ratio of equity to debt for computing the weighted average rate of return was changed to 35:65.

AMENDMENT OF GAS UTILITIES INDUSTRY LAW

Since its enactment in 1954, the Gas Utilities Industry Law has provided the regulations for gas rate setting and market entry to protect customers from abuse of monopoly power. However, since its enactment in 1954 and the first revision in 1970, the business environment surrounding the city gas industry has changed significantly. In 1965, for instance, city gas was mainly used by the residential sector with 59.6 percent of total sales, followed by the commercial sector at 21.4 percent, the industrial sector at 12.7 percent and other sectors used the balance of 6.3 percent. However, the sectoral composition for city gas use has changed significantly due to increased demand from commercial and industrial users. Both higher environmental standards and technological innovation has opened the way to greater use of city gas. For instance, by 1998, the residential sector's share had declined to 39.8 percent, the industrial sector had increased to 36.0 percent, and the commercial sector had declined to 16.4 percent with the residual sectors at 7.8 percent.

Fuel cost and supply conditions are very important to large volume customers such as industry and the commercial sector. They often also have some flexibility in their choice of fuels. Therefore, large volume customers advocated changes to the Gas Utilities Industry Law to allow city gas companies to offer (them) a greater variety of gas rates to reflect different demand patterns. Also, to allow choice of suppliers (the city gas companies), they strongly requested the revision of the Gas Utilities Industry Law to remove the supply area franchise monopoly.

Taking into account these concerns, the Urban Thermal Energy Subcommittee, a unit specialising in gas utilities' affairs under the Advisory Committee for Energy, [25] presented an interim report on the revision of the Gas Utilities Industry Law. This report proposed liberalising the market to facilitate competition among city gas companies. This would result in the lowering of rates to further enhance customers' benefit as well as the competitiveness of the city gas industry through the pursuit of increased efficiency.

In response to the interim report, the Gas Utilities Industry Law was amended in 1995 allowing large industrial customers with contracted amounts of more than 2 million m^3 per year[26] to negotiate prices and terms directly with suppliers. The amendments also included the following provisions:

- Gas utilities can offer service outside their service franchise areas;
- Non-city gas suppliers are permitted to supply to large industrial customers; and
- Gas tariffs shall, in principle, be free of regulation.

THE NEW SYSTEM OF GAS RATE SETTING

As described above, the Gas Utilities Industry Law was revised in response to pressure from large consumers. Not only this, but there were also claims for the lowering of rates by other sectors in light of the discrepancies in city gas rates. Table 13 and Table 14 show the differences in city gas rates among selected economies, highlighting the high rates prevailing in Japan. Table 15 illustrates the high cost structure of Japanese city gas rates. It shows that the cost structure in Japan is between four and five times higher compared with USA, UK and France.

Table 13 Comparison of City Gas Rate for Residential Sector in 1994

	Japan	USA	UK	Germany	France
Exchange rate base	100	44	29	54	49
PPP base	100	83	55	74	75

(Japan=100)

Table 14 Comparison of Average City Gas Rate in 1996

Japan	USA	UK	Germany	France
100	51	34	64	58

(Japan=100)

As Table 15 shows, costs other than the fuel cost significantly increase the total city gas cost. Taking the case of residential sector, for instance, population density per distribution line (population/km), is 1.5-3.0 times higher in Japan than in the USA, the UK and France (Table 16). However, annual sales volume per household is from half to one third smaller than USA, UK and France, resulting in higher costs per m^3.

Table 15 Comparison of City Gas Cost

yen/m^3	Japan	USA	UK	France
Fuel Cost	23.2	15.4	22.4	11.1
Cost for Business Operation	48.2	9.5	6.8	12.6
Depreciation Cost	8.5	1.5	1.2	3.4
Labour Cost	16.0	2.9	2.3	4.0
Other Expenses	23.8	5.1	3.4	5.2
Total Cost	71.4	24.9	29.3	23.7

Source: Institute of Energy Economics, Japan

Table 16 Residential Sector Consumption Characteristics

yen/m^3	Japan	USA	UK	France
Number of customers per 1km distribution line (number of customers/ km)	113	35	78	67
Annual sales volume per residential customer (m^3/ household)	349	1,932	1,266	1,203
"Annual sales volume per 1km distribution line (1,000 m^3/km)"	39	68	99	80

Source: Institute of Energy Economics, Japan

By taking into account of these factors, three methods were introduced in an attempt to lower city gas rates by improving the efficiency of the city gas industry's business operations. These are (1) "yardstick assessment", (3) raw material cost adjustment, and (3) load adjustment system.

YARDSTICK APPROACH

In order to create a "competitive" environment among the city gas companies while still permitting regional monopolies, one type of assessment called the "yardstick approach" was introduced. This approach makes comparisons of managerial efficiency levels among city gas companies when they renew their gas rates. Also, in recognition of the importance of companies' active involvement with improving efficiency, it was determined that the city gas companies are obliged to set targets and notify them publicly.

The "yardstick assessment" scheme resulted in successfully lowering gas rates. From January 1996 to January 1997, the three largest city gas companies lowered their gas rates by 0.47 percent, and the number of city gas companies that lowered their gas rates reached 201, about 80 percent of all city gas companies. Along with lowering rates, city gas companies announced their target levels for the improvement of managerial efficiency.

RAW MATERIAL (FEEDSTOCK) COST ADJUSTMENT[27]

In light of fluctuations in the exchange rate and feedstock prices, city gas companies are required to revise the raw material (feedstock) cost every three months,[28] so that the gas rate would reflect the changes in raw material cost.

LOAD ADJUSTMENT CONTRACT

City gas feedstock users and operators of boilers and air-conditioners are encouraged to shift their time of use with lower gas rates[29] to reduce the differences in load patterns between winter and summer, or between day and night. To achieve this, city gas companies are offering different types of contracts that more accurately reflect load patterns. There are 4 types of contracts: (1) Small Air Conditioner User, (2) Summer Air Conditioner User, (3) Air Conditioner User and (4) Time of Use.

TO FURTHER LOWER THE GAS RATE

After the revision of the Gas Utilities Industry Law in 1995, there were calls for further lowering of city gas rates. In 1996, the Cabinet adopted the so-called "Action Plan for Economic Structural Reform", to tackle the economic slowdown following the collapse of the "bubble economy". The Plan aims to provide some measures to create new industries to increase employment and to correct the economic structure that has led to a relatively high cost economy. This Plan includes the objective that "city gas companies would provide service comparable to the international standard by 2001". In response to this Action Plan, the Forum for Gas Industries' Structural Reforms was established in May 1997 as a private study meeting led by the Director of the Public Utilities Department, METI.

From May 1997 to September 1998, the Forum investigated the state of the city gas industry to make proposals on how to make the industry more competitive in policy terms. Major points of discussion were:[30]

- The situation of large volume customers after the revision of the Gas Utilities Industry Law;
- The state of gas wheeling service and how to enhance wheeling;
- How to expand load adjustment contracts and simplify the procedure; and
- Simplification of administrative procedures under the Gas Utilities Industry Law.

Reviewed the discussion points by the Forum, in February 1999, the Urban Thermal Energy Subcommittee, under the Advisory Committee for Energy, submitted an interim report to propose further revisions to the Gas Utilities Industry Law. In response to the proposal of the interim report, the Diet adopted a revised Gas Utilities Industry Law in May 1999. After the revision of relevant Ministerial ordinances, the Law came into force in November 1999.

The 1999 revisions of the Gas Utilities Industry Law aimed to achieve the following:[31]

- Further liberalisation of the gas market;
- Enhance consumer benefits by enlarging their choice of gas suppliers;
- Establish gas companies' autonomy; and
- Minimise the administrative interventions by METI and regulations.

The amendments can be broadly classified into two: (1) Revision of the city gas rate setting procedure, and (2) Revision of market entry regulations. The newly amended law is best characterised as providing a notification system that abolished the direct involvement of METI in the rate approval process so long as gas rates were being lowered, and reducing the threshold scope of large volume customers who can directly negotiate their supply contracts to 1 million m^3 per year. Major points of revision are summarised as follows.

REVISION OF THE CITY GAS RATE SETTING PROCEDURE

1) Retail Sales

- The rate approval system of METI is abolished and is changed to a "notification" system when city gas companies lower gas rates and change supply conditions that would benefit customers. On the other hand, when city gas companies propose to raise gas rates, they still have to pass through the METI approval process before actual implementation.
- In addition to the basic rate menu, customers can choose supply conditions from an enlarged rate menu.

2) Wholesale Sales

- The approval system for setting wholesale gas rates supplied through pipelines is changed to a "notification" system in an attempt to promote more efficient price setting by negotiation between the involved parties.

REVISION OF ENTRY REGULATIONS

In the large-scale supply sector, the following changes were made:

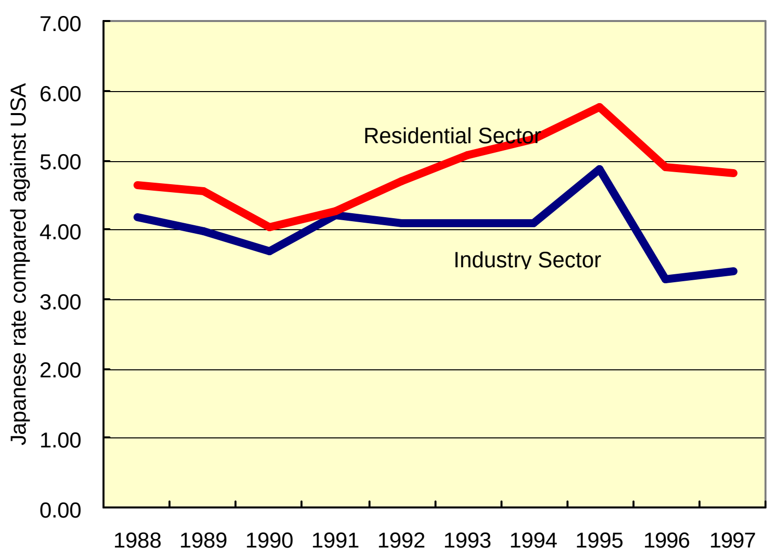
- The size of large volume customers who can directly negotiate rates with city gas companies is reduced to contracted amounts of more than 1 million m^3 per year; and
- The four major city gas companies are required to file transmission wheeling terms and conditions to METI to facilitate entry of suppliers with no pipelines of their own and publicly notify their terms and conditions.

Figure 15 shows the relative sectoral prices of natural gas compared against the USA. From 1988 to 1997, the relative price for industrial use shows a stable or downwards trend against USA. On the other hand, the residential price has been getting relatively higher compared with that of the USA. It is noticeable that the difference of relative prices between the industrial and the residential sectors is widening.

It is generally accepted that the development and progression of deregulation lead to the reduction of cross subsidies. Further, it is can be reasonably assumed that gas market deregulation is more advanced in the USA than in Japan. Given the foregoing, one may infer that the widening gap of prices between the industrial sector and the residential sector implies some possibility of cost shift from the former to latter, that is, the reduction of cross-subsidies from industrial consumers to residential consumers. There can be found another fact that can support this argument. As shown in Table 1, the price reduction for industrial consumers is about double that for residential consumers in the USA for the fifteen years to 1999. In other words, the increasing trend of the relative (Japanese) residential price combined with the relatively smaller reduction in the US residential price reinforces the inference about the reduction of cross-subsidies. Similarly, the decreasing trend of the relative (Japanese) industrial price together with the much larger decrease in the US industrial price strengthens the argument supporting the decrease in cross-subsidies to residential consumers from industrial consumers.

However, the argument above is not definitive by any means. Factors affecting the natural gas price are significantly different between the two economies. The earlier part of this section showed the difference in cost structures. It highlights that the number of residential customers per length of distribution line is smaller and costs other than fuel are (much) higher in Japan, leading to a higher level of cost per household. Also, the higher requirement for safety management in Japan[32] increases the cost. Therefore, for more concrete discussions of cross-subsidies in the Japan gas sector, more factors and the detail of actual cost allocation at the rate design stage need be investigated.

Figure 15 Japanese natural gas price compared against USA by sector



Source: IEA (2000), "Natural Gas Information"

SUMMARY

- Originally, government regulations permitted city gas companies to run their businesses under exclusive supply area franchises in recognition of the huge initial investment requirements and economies of scale. In turn, they had supply obligation to their service areas.

- To protect customers from monopoly power, city gas companies' tariffs were subject to a rigorous approval process involving government, experts and the public.

- Three steps were involved in the rate setting process. Firstly, city gas companies estimated the total costs for supply, secondly, they allocated the estimated total costs according to function, and thirdly, they formulated their gas rate menu based on the type of customers and type of demand. This menu was submitted to the Minister of METI and after consulting with experts, the Minister would approve the the gas rate on condition that it would not unduly affect inflation.

- Due to changes in the business environment, the Gas Utilities Industry Law was revised in 1995 and 1999 to provide further rate options for consumers based on their demand patterns. Also, the 1995 revision permitted city gas companies to supply beyond their exclusive supply areas.

- The Gas Utilities Industry Law revision of 1999 abolished the rate approval system of METI changing it to a "notification" system when city gas companies lowered gas rates and changed supply conditions that would benefit consumers.

- Although more factors and actual cost allocation data need to be analysed, the available information shows that there is a possibility that the allocation of gas supply costs has shifted from industrial consumers to residential consumers in the past ten years or so.

INDONESIA

Indonesia has been utilising its natural gas resources either for export or for domestic use since 1963. Japan and Korea are the largest buyers of Indonesian LNG with Chinese Taipei also being a customer. Singapore has begun importing piped gas from the West Natuna field. In the domestic market, natural gas has been utilised to support strategic industries, such as steel and fertiliser. Today, Indonesia is the biggest natural gas producer in Southeast Asia.

MARKET SITUATION, HISTORY AND DEVELOPMENT

The Indonesian natural gas industry began in 1963, when natural gas was first utilised as a raw material in the fertiliser industry by the government-owned enterprise PUSRI (Pupuk Sriwijaya) I A. Since then the industry has gone through three stages of pricing development. In the first two stages, the price of natural gas was pegged to the price of crude oil, while the present pricing method follows the netback market value concept.

In the export market, the government's share in the production sharing contract (PSC) is about 52 percent. In 1999, exports of LNG and LPG amounting to 4,950.9 MMSCFD and 25.3 MMSCFD, respectively, comprised around 60 percent of production [Directorate General of Oil and Gas, 1999]. Around 93 percent of the LNG exports were to Japan and Korea. Recently, Indonesia has developed a new market for non-domestic use of natural gas by exporting gas from the Natuna field through pipelines to the neighbouring economy of Singapore under a long-term contract.

On the domestic side, natural gas is used as fuel in electricity generation, industry, and household activities, and as a raw material in a number of industries such as the fertiliser, cement, petrochemical and steel industries. Domestic natural gas consumption is around 40 percent of production.

REGULATORY ISSUES

The State Constitution of 1945 stipulates, "Land and water and the natural resources contained therein are managed by the State and are to be used for the maximum benefit of the people's welfare." This constitution is applied by the Government Official Regulation No. 44 of 1960, which described in detail the utilisation of natural resources in Indonesia. The Law No. 8 of 1971 appointed Pertamina (the state-owned oil and gas company) to be the exclusive company to manage the oil and gas industry from the field to the customer. The latter Law also states that private companies would be allowed into the business only as a contractor of Pertamina. The state-owned gas company, PN Gas (Perusahaan Negara Gas), which has operated since 1985, is the utility company that supplies city gas. The Government Regulation No. 37 of 1994 changed PN Gas' name to PT PGN (Perusahaan Terbatas Perusahaan Gas Negara) (Persero). The company was granted additional authority in the transmission and distribution lines to serve domestic gas supply.

The exploration of oil and gas is regulated by the Ministry of Energy and Mineral Resources and is by way of production sharing contracts (PSCs) between Pertamina and private contractors. In addition to the Ministry, the Directorate General of Oil and Gas also has the authority to formulate regulations for the determination of gas prices for particular consumer groups.

MARKET MECHANISM

The domestic policy of natural gas pricing encourages investment in the industry and encourages the domestic use of gas. Therefore, the pricing policy allows the highest possible payment to the producers and the lowest possible price to major domestic consumers. There are essentially two sides to the pricing arrangements, the first between the government and the private contractors on the production side and the other, between the government (in this case, Pertamina) and the bulk consumers.

PRICING FOR PRODUCTION

In the PSC agreement, gas prices are negotiated on a field-to-field basis, and on the economics of gas field development. After all operating costs are deducted, the yield is divided in a manner that gives the contractors about 52 percent of the total with the government receiving the balance. The contractors also pay 44 percent tax, which includes corporate income tax and dividend tax.

The price of gas is determined by the cost of gas, which consists of the cost of production, processing costs and transportation costs. The production cost depends upon site characteristics such as whether it is on- or off-shore and the depth of well and varies between US$0.3 and US$1 per MMBtu. The cost of processing includes separation, dehydration, and CO_2 and H_2S removal.

PRICING FOR CONSUMERS

The downstream side of the gas industry is served by PT PGN (Persero), which buys natural gas from Pertamina and sells it to consumers. Pertamina also directly supplies natural gas to very large consumers such as power generators and petrochemical plants.

The toll for the transportation of gas from the field to consumers depends on distance. For example, the toll from Asamera to Duri (about 450 kms) in Sumatera is US$0.55/MMBtu for the whole distance. It gives PT PGN, the owner of the transmission pipe, an internal rate of return (IRR) of 11.5 percent. For longer distances, the toll fee could be as low as US$0.0012/MMBtu/km. For small customers supplied from a distribution pipeline, the transportation cost may be up to three times the former.

The domestic natural gas market has some specific characteristics in the pricing mechanism. The government has a policy that a number of industrial subsectors should be given subsidies that are expected to be equally distributed for the welfare of the people. The fertiliser industry, for instance, enjoys a low price (see Table 17) of about US$1/MMBtu in order to allow farmers to buy cheap fertiliser and so support agriculture. On the other hand, the state-owned electricity utility PLN has to buy natural gas at a take-or-pay price of around US$3/MMBtu and has to sell electricity in the local currency, the rupiah. As a result PLN has suffered considerable losses, since in addition to the higher price of the gas that it uses, the rupiah has also devalued significantly in the last few years.

The government's application of subsidies for natural gas is estimated to be around 28.4 percent of reference prices at international market value [IEA, 1999b]. The subsidisation of natural gas is part of a general subsidy that the government puts on energy, which is estimated to accounted for an average of 27.5 percent of the reference price. For the purpose of maintaining this subsidy, the government has budgeted a fund of US$3.6 billion (assuming an exchange rate of 15000 Rupiah = US$1) in the fiscal 1998/99 budget period. This amount was over half of the government's 1997 budget, as estimated by Pertamina. Thus, fuel subsidies comprise a large proportion of the government's expenditures.

The scale of energy subsidies largely explains why it is a politically charged issue in Indonesia. Indonesia was the economy hit hardest by the Asian financial crisis of 1997/98. In order to recover from the crisis, the reduction and phasing out of fuel subsidies was one of the first issues to come up for policy consideration. When the economic reform process started in 1998, the government, under the recommendation of the International Monetary Fund (IMF) among others, reduced the subsidies for a number of petroleum products, resulting in price increases of over two-thirds. The population, who had already suffered badly from the crisis, protested this measure violently and the government had to revise the price increases just several days later. This proved that the issue of fuel subsidies will remain a controversial issue in the government's efforts to solve broader economic problems unless there is a stronger legal basis for implementation of the policy.

To further the process of subsidy reform, the Ministry of Mines and Energy (title of the ministry at the time) prepared the oil and gas bill and introduced it to the parliament in mid-1999. As expected, the subsidy issues contained in the bill were subject to a long and unfinished debate within the parliament. After going through several tough debates, it is expected that the legislative body will approve this bill in the second quarter of 2001.

Another important issue in the proposed bill is the liberalisation of the downstream oil and gas industry. Essentially Pertamina would lose its monopoly and end-use markets would be opened to full competition in a transparent manner. PT PGN (Persero), which operates the transmission and distribution lines, will also be separated into smaller subsidiary transmission and retail companies. It is anticipated that the consumer price of natural gas will be reduced which will encourage the use of natural gas in sectors such as residential, transportation and small industry.

PROPOSED PLAN FOR PRICING POLICY

The negative aspects in the natural gas industry have prompted a number of proposals on both the supply and the demand sides to be assessed in the near future. On the upstream side, there has been a proposal to modify production incentives, in which the share of the government in the PSC will to be reduced so that the larger share of the contractor could reduce wellhead prices, and hence increase natural gas' competitiveness vis-à-vis other fuels. On the downstream side, another proposal is to move the allocation of the government fuel subsidy from diesel fuel to natural gas for electricity generation, especially for the state-owned PLN, as one of the largest consumers of fuel. Under this proposal, the government could reduce increasing diesel fuel imports, and help encourage higher value added in the electricity generation industry at the same time. Since electricity generation is expected to consume a greater volume of natural gas, marginal gas fields around the natural gas pipeline infrastructure will become

Table 17 Contract Prices of Natural Gas for Domestic Use

	Consumer	Business	Area	Periods		Price per MMBTU	
				From	To	Currency	Price
1	PT. Kaltim Pacific Amonia	Amonia	East Kalimantan				
2	ITP Cirebon (Ex TMPC)	Cement	West Java	1985	2000	US $	3.00
3	Bermis SW. (FG)	Ceramic Tile	West Java	1989	-	US $	0.15
4	PGN Jakarta/Bogor	City Gas	West Java	1986	2001	Rp	3,100.00
5	PAN Gasindo B.S.	CO2	West Java	1996	2005	Rp	3,100.00
6	Cikarang Listrindo	Electricity	West Java	1993	2003	US $	2.45
7	PLN Gresik (ARBNI)	Electricity	East Java	1992	2011	US $	2.53
8	PLN Medan	Electricity	Aceh & N. Sumatera	1985	2001	US $	3.00
9	PLN Surabaya (Kodeco)	Electricity	East Java	1987	2002	US $	2.53
10	PLTG Muara Karang	Electricity	West Java	1994	2004	US $	2.45
11	PLTGU Tanjung Batu	Electricity	East Kalimantan			US $	3.00
12	Pupuk Kaltim I	Fertilizer	East Kalimantan	1982	2001	US $	1.00
13	Balikpapan Refinery	Fuel	East Kalimantan			US $	0.135xAr*
14	Wailawi Field (VICO)	LPG	East Kalimantan	1996	1999	US $	1.70
15	Methanol Bunyu	Methanol	East Kalimantan			US $	1.42
16	Akzonobel C.I. BV	Paint/Synthetic	West Java			US $	3.10
17	Kertas Kraft Aceh	Paper	Aceh & N. Sumatera	1988	2008	US $	1.50
18	Fajar Surya Wisesa	Paper Board	West Java	1996	2006	US $	2.90
19	Petrokimia Gresik	Petrochemical	East Java	1993	2013	US $	2.00
20	Seampless Pipe I.J.	Pipe	West Java	1994	2008	US $	3.00
21	Krakatau Steel	Steel	West Java	1982	1998	US $	0.65
		Steel	West Java	1982	1998	US $	2.00
22	Sri Melamin Rejeki	Tableware	South Sumatera	1993	2013	US $	3.50
23	PT. Indorama	Textile	West Java			US $	2.75x(1+0.01)(n-1)
24	Henrison Iriana	Wood	Irian Jaya	1992	1998	US $	0.97

* Ar - Average price of Indonsian crude oil by ICP
Source: Ministry of Energy and Mineral Resources, 2000

more economically feasible to develop.

The proposal on the downstream side seems to be more acceptable than that on the upstream side as the latter is seen as threatening to reduce the government's income from the PSC contracts. The government still has to await Ministry of Finance approval as to whether one or both proposals will be implemented.

SUMMARY

- The natural gas industry is regulated under the State Constitution of 1945, government regulations, and a law that has appointed the state-owned oil company, Pertamina, to manage the oil and gas industry along the whole supply chain.

- The state-owned gas company, PT PGN, was appointed as a monopoly utility to supply city gas in 1985, and is currently granted additional authority to operate the transmission and distribution lines to serve domestic gas supply. It is expected that PT PGN will be separated into transmission and retail companies under new legislation.

- Producer prices are determined by production costs and agreements between the government (Pertamina) and contractors. Consumer prices take into account the transportation cost and other supply costs, as well as subsidies paid by the government. Additional subsidies are also applied to some other consumers such as the fertiliser industry with the intention of improving the distribution of wealth.

- The fuel subsidy issue is controversial due to a disagreement between parties that support efforts to phase it out and ones who defend the subsidy for social welfare reasons. Thus natural gas market restructuring plans are facing considerable opposition. However, legislation for oil and gas industry reform should be approved soon and this will put gas markets on a more commercial basis.

- In the near future, it is proposed that the government will shift a subsidy currently applied to diesel oil to natural gas for electricity generation, and that the government share in the PSC will be reduced to provide an incentive for contractors to reduce wellhead prices in order to increase the competitiveness of natural gas.

CHAPTER 6

SUMMARY AND CONCLUSIONS

In this report, a survey of the literature and practices on utility pricing has been undertaken, particularly as they apply to the issues of pricing, subsidies and cross-subsidies in natural gas end-use prices. Since a focus of the discussion is on cost allocation to different products and services and consumers, three cost-based rate-making methods are reviewed. Although the FDC method is the most commonly used and subsidy-free under certain circumstances, it has shortcomings in that, amongst others, there is no consideration of efficiency in the method. That is, the method makes it possible to recover total costs but does not take marginal costs or price elasticities into account. Similarly, while the cost-axiomatic approach may be useful for incorporating some notions of equity or fairness in gas prices, it is difficult to link notions of efficiency to this method.

A price is (cross-)subsidy-free if the revenue from the service under the price is greater than or equal to its incremental cost and less than or equal to its stand-alone cost. In practice, however, this definition of subsidy-free price raises conflicts and confusion between consumers. In other words, it is possible, perhaps usual, that an individual consumer thinks of himself as subsidising others whereas the price he pays is, in fact, subsidy-free. The individual may well want to have a new arrangement under which he will pay less than currently, or, theoretically speaking, to defect from the current coalition to which he belongs and to form a new one. This implies that the real issue concerning subsidies and cross-subsidies may be more focused on fairness than on efficiency.

In this regard, some notions of fairness have also been discussed. The single most important conclusion is that these notions are often incompatible with each other and there may be no feasible price solution that satisfies all the fairness criteria. For example, there may appear just one set of prices that satisfy a set of cost-sharing axioms, which is very much divorced from any efficiency criteria.

More generally, theory says that the constraints of achieving fairness work to reduce the feasible set of tariffs and may leave little or no room for surplus maximisation. It should also be noted that theory is silent about welfare maximisation. Further, the social welfare function and constraints perceived by policy makers or regulators in general may be different across economies. Regulators may be regarded as attempting to make an optimal choice based on their perceptions of social welfare functions and constraints in a second-best or third-best world. The constraints include short- and long-run development paths, efficiency, equity (fairness), and other social objectives.

Some explicit subsidy mechanisms have been found in use. Examples are the Chilean rural electrification program and the U.S. Federal government's auctioning of subsidy funds for universal services in telecommunications. It is conceivable that such mechanisms could be adopted in natural gas markets. The broad approach is one of government procurement of universal services. Issues and problems concerning the incentives of service providers in the bidding remain. One issue is how to optimally design the auction mechanism. Another recent argument about the cross-subsidy problem is that traditional cross-subsidies should be retained within the scope of universal services if any subsidy is to be provided at all. This shows that many policy makers and economists still acknowledge the necessity of subsidisation for certain services and consumer groups.

As natural gas markets become more liberalised and deregulated, the scope for subsidies and cross-subsidies is reduced. However, while it is still true that there are less cross-subsidies within a liberalised subsector, cross-subsidies remain possible between liberalised and non-liberalised subsectors.

Whether an economy is developed or not, it has a certain concept of small consumers vis-à-vis large consumers. Within the market reforms framework, a small consumer tends to be defined as one who may need protection by the regulator from monopoly power while large consumers are those who have supply options within or outside of a specific energy market. Essentially all residential users may be regarded as small consumers relative to this definition. Protective measures include price controls, minimum service level requirements, supply obligation, disputes resolution procedures and supplier of last resort rights. All these measures incur direct and indirect costs, raising again the issue of efficient and equitable ways of financing them. One notable trend is that the scope of small consumers is becoming narrower as market reforms progress.

There are some regional or national features concerning subsidies and cross-subsidies in natural gas end-use prices. In Canada and the USA, albeit on an empirical basis, deregulation may have eliminated or reduced cross-subsidies in transportation rate structures and in retail distribution markets. At the same time, due to efficiency gains in commodity gas markets, overall inflation-adjusted prices for all classes of consumers have fallen. Regulatory changes over the last two decades have helped to encourage more transparent and cost reflective transportation rates. Retail markets are slowly being opened up to competition with the potential to reduce or remove cross-subsidies.

In Japan, the recently amended Gas Utilities Industry Law provides further rate options for customers and allows city gas companies to supply beyond their franchise areas. METI's rate approval system has been abolished and changed to a notification system, if city gas companies lower gas rates and change supply conditions that would benefit customers. To facilitate network access by third parties, the creation of fair, cost reflective access tariffs is under consideration.

In Korea, efforts have been made to reduce cross-subsidies from the power generation sector to city gas consumers by, for example, further deregulation and changes to price structures. However, there remains a clear cross-subsidy to gas for air-conditioning of commercial buildings from other types of end-uses - the final price level has been below the gas cost for some time - to improve the consumption pattern of gas and air quality. Many agree that the initial subsidy policy has contributed to the fast penetration of natural gas into non-electricity uses and reduced the unit supply cost more rapidly than would otherwise have been the case. Albeit empirical, this pricing policy now has substantial non-financial benefits such reduced greenhouse gas emissions accruing to it although it may be argued that such effects can be achieved through alternative policy instruments.

In Southeast Asian economies, governments support strategic industries such as steel and fertiliser manufacturing with price subsidies for inputs such as gas. There are ongoing efforts to improve the effectiveness of such policies. For example, the Indonesian government is reallocating diesel fuel subsidies to natural gas for electricity generation.

In Oceania, although difficult to separately identify, historically there have been cross-subsidies in the sector. Due partly to competitive pressures, these have either been completely eliminated or are being phased out. New Zealand has a small but well-developed reticulated gas market. Deregulation and market reforms in the 1990s have seen the gradual removal of cross-subsidies that have existed with household prices having risen faster than prices for industry in the last decade. In Australia, cross-subsidies that existed prior to the mid-1990s have been eliminated or reduced for similar reasons. The fragmented state of the industry and the lack of basin to basin competition means that there are currently wide disparities in prices between regions. These variations are likely to disappear as new interstate pipelines are completed and Australia achieves a more integrated gas transmission system.

In summary, different ways and objectives of subsidisation exist across industries and nations within the APEC region according to industry characteristics, economic development imperatives and consideration of other social policy concerns. After all, any policy, including subsidisation, is decided through a political process reflecting a variety of measurable and non-measurable benefits and costs. If this statement is accepted, there remains the issue of so-called best practice. Certainly, best pricing practices emphasise efficient pricing and the existence of (cross-)subsidies means that prices are distorted. However best pricing practice does not seem to exclude subsidisation if the term "best practice" means prices that would give a "best" result in a second-best world.

The appropriateness of subsidisation as a policy instrument depends on what the policymaker tries to achieve with it. If there are positive externalities, subsidies may serve to internalise them, with the optimal design of the subsidy mechanism and financing scheme left to be the focus of policy discussion - financing with general tax revenue, financing with funds raised within the energy sector or within the gas sector, etc. On the other hand, if the policy goal were to achieve certain spill over effects that could be more effectively achieved through incomes policy, an energy subsidisation policy would be the wrong choice of instrument. This is where, for instance, the targeting problem arises, since subsidisation involves income redistribution as well as price distortions between subsidising and subsidised individuals.

Subsidies or cross-subsidies are not a bad policy instrument per se, so the pertinent issue is subsidy reform, not subsidy removal.

Endnotes

1 This is (usually) taken to mean gas consumed in the household, commercial or industrial sectors, that is, non-feedstock gas.

2 This theory is called the theory of second best. See, for example, Lipsey, R. E. and K. M. Lancaster.

3 Consumers are said to be "on-system" if the prices they pay are from a menu of options that is also available to other consumers.

4 Consumers are said to be "off-system" if the prices they pay have been directly negotiated between them and the supplier. In this way, the tariff is unknown and unavailable to other consumers.

5 See, for example, Irwin, T., "Price Structures, Cross-Subsidies, and Competition in Infrastructure", Public Policy for the Private Sector, Note No. 107, The World Bank, February 1997.

6 This definition draws on Crew, M. A. and P. R. Kleindorfer, The Economics of Public Utility Regulation, Cambridge: MIT Press, 1986, pp. 24-25.

7 This section draws on Mitchell, B. M. and I. Vogelsang, Telecommunications Pricing: Theory and Practice, Cambridge, Cambridge University Press, 1991, pp. 33-34.

8 This section draws on Brown, S. J. and D. S. Sibley, The Theory of Public Utility Pricing, Cambridge University Press, 1986; and Mitchell, B. M. and I. Vogelsang, Telecommunications Pricing: Theory and Practice, Cambridge: Cambridge University Press, 1991.

9 Or, conversely, removal of cross-subsidies could be one of the main reasons for the introduction of competition.

10 1 m^3 = 10,500 kcal.

11 1 m^3 = 10,000 kcal.

12 Carrier of Last Resort

13 The core services to be subsidised include: single party service; voice grade access to the public switched network; Dual Tone Multifrequency signalling or its functional equivalent; access to emergency services including, in some circumstances, access to 911 and Enhanced 911 ("E911"); access to operator services; access to interexchange service; access to directory assistance; and toll-limitation services for qualifying low-income consumers.

14 Section 254(b) of the Act. Quoted from Sorana, V., "Auctions for Universal Service Subsidies", Journal of Regulatory Economics, Vol. 18, No. 1, June 2000, pp. 33-58.

15 Ibid.

16 See the discussion above about the deadweight loss of a subsidy. In the case of the deadweight loss of a tax, the deadweight loss arises from an increased price level a consumer pays and the resultant decrease in consumption. Also, there will be additional deadweight losses from the consumption of subsidised core services, which we do not deal with here.

17 The discussion of the Chilean case draws on Jadresic, A., "Auctioning Subsidies for Rural Electrification in Chile",

Public Policy for the Private Sector, The World Bank, Note No. 214, June 2000.

18 This section draws on the reply to the APERC's questionnaire from the Mexican EGEDA contact.

19 Prior to November 1999, gas companies needed to have approval from METI in setting prices to final consumers.

20 Applying the stringent definition of cross-subsidy creates a wide range of subsidy-free prices. Hence, even though one often presumes that the cross-subsidy existed in the wholesale supply costs, precise calculation may prove otherwise. In the discussion of the cross-subsidy problem that follows, it refers to the pricing practice of explicitly permitting the possibility of cross-subsidy rather than acknowledging the actual existence of cross-subsidy in Korea.

21 Gas cost means the feedstock cost of KOGAS, the monopoly wholesale supplier.

22 Of related note, Laffont and N'Gbo (2000) showed with a formal model that in financing of network expansion, cross-subsidies may be a useful second best mechanism in developing countries without an efficient tax system.

23 The former Ministry of International Trade and Industry (MITI) was renamed the Ministry of Economy, Trade and Industry (METI)on 6th of January, 2001. Henceforth, METI is used.

24 A consultative body created by statute in METI to "investigate and deliberate on important matters" relevant to the energy sector.

25 As of September 1998, the number of large volume customers was 726 comprising 34 percent of total sales volume.

26 Determined in 1995.

27 The LNG based city gas rate is adjusted every three months. The LPG based city gas rate is adjusted every six months.

28 These gas rates are not subject to the METI approval process.

29 Hideo Hasegawa (1998), "Energy Deregulation and its Impacts on Gas Utilities", Energy in Japan, No.154, November 1998.

30 MITI/ANRE (2000), "Energy in Japan - Facts and Figures", February 2000

31 We do not consider here whether the level of safety management cost is warranted or optimal against comparable standards among economies.

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