Chapter 3 Policies and Regulatory Systems for Natural Gas Use Promotion

3-1 Reviews on Current Systems and Discussions

3-1-1 Existing Statutes and Policies Relevant to Natural Gas

There is no consolidated gas regulatory system established so far to nationally control the gas industry naturally since use of natural gas is quite new to the Philippines. Institutional base for nationally creating gas policies and systems, however, has been in existence as are demonstrated by the existence of the Department of Energy (DOE) and Energy Regulatory Commission (ERC). Existing natural gas regulations are incorporated in pieces in the petroleum related statutes listed below although new regulatory reform is being conceived or already drafted based on the result of an Asian Development Bank project.

Major existing statutes relevant to gas policies are chronologically listed in the following. More detailed description on each statute is given in the Annex 3-1 attached to the end of this chapter.

(1) Legislative and Presidential Level Statutes

(i) Commonwealth Act No.146 (CA146) of 1936 or the "Public Service Act"
(ii) Petroleum Act of 1949 (Republic Act 387, June 18, 1949) as amended
(iii) Republic Act No. 6173 (RA 6173 Oil Industry Commission Act, April 30, 1971)
(iv) Presidential Decree No. 87 (or PD 87, Dec. 31, 1972)
(v) Presidential Decree No. 1206 (PD 1206 Creating the Department of Energy, October 6, 1977)
(vi) Presidential Decree No. 1700 (PD 1700, Granting the Board of Energy the Power to Regulate Pipeline Concessionaires, July 10, 1980)
(vii) 1987 Constitution of the Republic of the Philippines
(viii) Executive Order 172 of 1987
(ix) Department of Energy Act of 1992 (Republic Act 7638, December 9, 1992)
(x) Downstream Oil Industry Deregulation Act of 1998 (Republic Act No. 8479, July 28, 1997)
(xi) The Tax Reform Act of 1997 and The National Internal Revenue Code of 1997
(xii) Philippine Clean Air Act of 1999 (RA No. 8749, 1999)

(xiii) Presidential Decree No. 314 (PD314 of November 2000) "Modifying the Rates of Import Duties on Imported Crude Oil and Selected Refined Petroleum Products under Section 104 of the Tariff and Customs Code of 1978 (PD 1464 as amended)"

(xiv) An Act Granting First Gas Holdings Corporation A Franchise in Luzon (Republic Act No. 8997, January 11, 2001)

(xv) Electric Power Industry Reform Act of 2001 (RA9136, June 8, 2001)

The Department of Energy Act of 1992, among above statutes, expressly declares the national energy policy as:

(a) to ensure a continuous, adequate and economic supply of energy with the end in view of ultimately achieving self-reliance in the country's energy requirements through the integrated and intensive exploration, production, management and the development of the country's growth and economic development and taking into consideration the active participation of the private sector in the energy resource development, and

(b) to rationalize, integrate and coordinate the various program of the government towards self-efficiency and enhanced productivity in power and energy without sacrificing ecological concerns.

(2) Existing Regulations Relevant to Gas

On the level of regulation, guideline and official opinion, important rules in the natural gas sector are as follows:

(i) "The Policy Guidelines on the overall development and utilization of natural gas in the Philippines" (DOE Circular No. 95-06-006, June 15, 1995)

(ii) "Rules and Regulations Implementing Section 5 of DOE Act of 1992 or RA 7638" (Energy Regulation ER 1-94, May 24, 1994)

(iii) Department Circular No. 2000-03-003 (March 17, 2000) giving details to the allocation of the fund from power generators.

(iv) Department of Justice Opinion No. 95, S. 1988 (May 11,1988)

(v) Department of Justice Opinion No. 46, S.2000 (June 6, 2000)

Contents of these regulations are also described in the latter half of <u>Annex 3-1</u>.

(3) Energy Security Policy and Gas Import

The declaration in the Department of Energy Act of 1992 implies that the national energy effort focuses on self-reliance and self-efficiency, i.e., on supply of energy from domestic grounds. The energy supply security is surely important for the growth of the nation and industry, and indigenous energy saves foreign currency reserves with successful development. Ecological concern is also addressed in the Act together with the security, being appreciated.

In an environment of eventual need of mixing imported energy into the total national energy supply scene, however, maximizing the use of preferred energy resources like gas to an extent to benefit the nation may be an additional option that must be considered. This notion is already recognized in the Philippines and is additionally addressed in a regulation, i.e., the DOE Circular No. 95-06-006.

After considerable national effort of exploration of indigenous petroleum and gas and successfully finding and developing important hydrocarbon reserves, however, it seems that the country still needs to depend on certain imported energy for future growth, although continuing searching for domestic resources is still valuable. While the use of indigenous resources for domestic consumption contributes to the near term security of supply, it is equally invaluable to prolong the life of such resources for the future generations by importing alternatives today when and if they are economically available, adding a long term energy security.

Another important role of limited indigenous energy is to contribute to energy security by responding to demand fluctuation adjustment requirement. Energy import through inevitable long term contracts with take or pay clauses may require mechanisms to adjust supply and demand in an environment of climatic and economic demand fluctuations requiring storage, whose role indigenous reserves could partly play.

Environment is a national security issue, too. Promoting the use of environmentally benign and safer fuel, either domestic or imported, eventually relieves the social tension within the nation and raise the national status internationally.

While we reiterate the gas import option in the Philippine energy picture, however, there is certain limitation, too. Import requires foreign currency which indigenous energy development could save, and excessive dependence on imported gas may make the gas trade negotiators lose leverage in winning favorable terms in the contracts. Gas power plants, for example, are less in required Capex compared to coal plants, but based on the current gas prices, coal plants may be cheaper in variable operating costs due to lower coal prices on thermal basis and may win in the actual dispatching, which may limit the use of gas for power. There will be, therefore, an optimal share of gas in the power mix, which may be difficult to quantitatively determine at the moment.

The country will thus seek to grow with the mixture of indigenous and imported energy resources just as Japan does, while the Philippines is better positioned in view of availability of other energy resources like hydro and geothermal. How to design an effective spectrum of supply of energy resources, indigenous or imported, to assist the national economic growth and environmental improvement will be on agenda. This suggests that rationalization of energy downstream rather than upstream will be more important at a time in the future economic development. Natural gas will then become more important in the downstream.

3-1-2 Legislative, Regulatory and Institutional Systems on Gas in Place

(1) Energy Non-price Institution - DOE

Just for review on institutional matters, the DOE is the prime institution for energy. The Department of Energy Act of 1992 has created its bureau offices under the Secretary and under- and assistant- secretaries for: (1) Energy Resource Development, (2) Energy Utilization Management, (3) Energy Industry Administration, (4) Energy Planning and Monitoring, and (5) Administrative Support. The organization illustrated in Annex 3-2 reflects the Act. Further attached to this Department are PNOC (The Philippine National Oil Company), NPC (the National Power Corporation) and NEA (the National Electrification Administration).

The Act has given the Department all energy related, but non-price, regulatory powers and transferred relevant functions from other departments.

(2) Pricing Institution

The price regulatory power for energy utilities seems held by the Energy Regulatory

Commission (ERC) created by the Electric Power Industry Reform Act of 2001 (RA9136). The ERC is now not only a pricing regulatory institution but also administers certain power industry grid codes and permits, etc. Its replaced former body, the Energy Regulatory Board (ERB), established by the E.O. 172 (1987), had the function of price regulation including gas. There is a concern that RA 9136 limits the functions of the ERC to electricity only; thus some adjustment is expected for the future gas price regulations. The Commission is semi-independent and quasi-judicial under the Presidential Office.

A distinctive nature of the gas regulatory authority is that price and non-price regulations are divided by separate government bodies as well as other relevant jurisdictions are fragmented over different departments or agencies. The ERB had been thought to regulate future piped gas prices and transmission fees as well as other relevant tariffs judging from existing statutes.

The ERC does not have a pricing power on items legally defined as "market prices". The market price is clearly applied to the gas in the pipeline from gas wells to the gas processing plants, which is under upstream service contracts. There has been some debate on the gas in the gas processing plant since the time of enactment of the Downstream Oil Deregulation Act of 1998 (RA8479), on whether gas is legally included in the deregulated "downstream oil" or either regarded as "piped gas" defined in the CA146 of 1936 and in Petroleum Act of 1949, which require regulation by the ERB (now ERC). An official opinion of DOJ is waited to judge this as a market price considering jurisprudence and a legal trend represented by the RA8479, since this will be relevant to future LNG terminals.

(3) Franchise, Public Utility, Concession and Right of Way

Gas transmission and distribution businesses are a public utility or a public service stipulated in the Constitution, CA146 and RA387 (Petroleum Act of 1949), as interpreted by the DOJ Opinion No. 95 of 1998, which require first obtaining the prior grant of franchise, certificate or authorization from the State (i.e., Congress) or duly designated agency at the start of their operation. While the Congress holds such power to grant franchise on one hand, the CA146, other relevant laws and DOJ Opinion No. 46 of S2000 suggest that such power to grant a certificate has now been alternately devolved to the DOE.

It may be an enormous hurdle for potential private sector entrants in the gas transmission and distribution business to have to go to a legion of Congressmen to lobby and obtain franchise or certificates every time of beginning such a project. A new and simple legislative decision to empower the relevant authorities to grant a franchise under certain conditions is recommended to encourage the private initiative.

The authority regarding pipeline concession, which awards a person or an entity non-exclusive right to construct and operate pipelines, was vested with the Director of Mines by the RA387. The author understands that this non-price regulatory power is now vested with the DOE by RA 7638 (DOE Charter), with environment related matters to be consulted with the Department of Environment and Natural Resources.

The RA387 stipulates that a concessionaire be authorized the right of way for pipelines and relevant facilities on either private or public lands. Also Article III, Sec.9, of the Constitution stipulates that "Private property shall not be taken for public use without just compensation", which is interpreted to implement an inherent power of the State, the power of eminent domain, which in turn includes granting the right of way for public work. Article XII, Sec.2, stipulates that all the lands of the public domain are under the full control and supervision of the State, benefiting public entities for public service business in view of the right of way. NPC and PNOC are given the potential power of eminent domain for the right of way of pipelines by respective charter laws.

Private sector companies, instead, generally face tough negotiations to secure the right of way, while pipeline concessionaires are permitted by RA387 to negotiate with landowners for it. A help from legislature may be needed. Manila Gas and First Gas are specifically given the power of eminent domain by respective specific laws awarding franchise, which allow those companies to negotiate for it in return for just compensation in using the necessary lots for pipelines and relevant facilities. Use of public roads and highways for the same purposes is considered to become legitimate after negotiations with the Department of Public Works and concerned local governments.

(4) Common Carriage

The RA387 (Petroleum Act of 1949), Art. 86, requires that gas pipelines to serve as common carrier, with surplus capacity to be surrendered for public and non-discriminatory use, being often called third party or open access, of which some are mandatory as is called mandatory open access (MOT). This article is a pioneering one for common carriage, which is now prevailing in many developed and developing countries having matured gas network and market. It is rare that such serious provisions are readily applied before an industry development. While it is mandate to observe the law and any potential investor will plan accordingly, however, application of this provision to gas is unusual in a country where virtually no gas pipelines exist. It may be beneficial to a gas project that common carriage could raise the performance of pipelines with increased gas throughput by the activities of third party gas sellers and buyers.

A concern arises at the same time on financing. When a project sponsor plans a gas network, which is heavily capital intensive and requiring financial recovery through long term operation, in an expectedly growing market, he will assume to respond to the future demand growth and will design a larger capacity, say twice, to accommodate the future expanded market. Financiers will expect the facilities to be operated in good financial performance with sufficient debt coverage ratio and investment return.

The concern of whether or not pipelines and distribution networks in the environment of open access are financeable is very serious. Investment in open access pipelines in matured countries, according to an article, is not seen as a insurmountable problem by an officer of the European Investment Bank[1)]. But the article says private banks are not necessarily in its favor and this statement may not apply to developing countries where country risk is deemed high.

Sound gas business performance requires a good load pattern, which directly affects the pipeline load factor and economics. Then there is a possibility that the sponsor prefers customers having good pattern of gas consumption and quantity as planned. We hope that third party access is at least not mandatory or intimidate long-term operation plan with productive market intended for. Also sponsors should be allowed to secure productive market at least in an period long enough to recover the investment. It is common that gas reaches only regions and customers where economics permits.

The JICA Master Plan assumes that large customers, including power generations, will

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[1)] International Energy Agency, *Natural Gas Transportation-Organizations and Regulation*, 1994 first use gas for economic reasons, since gas supply to smaller customers is clearly costlier in view of unit gas (service) cost. We hope to assume that "non-discriminatory" access will not exclude this economic principle and allows due preference on size and type of customers to be chosen accordingly at least in the infant and embryonic stage of the industry. The investors or sponsors may want certain virtual exclusivity for a scope of market for certain period due to financial security reasons.

(5) Industrial Structure

Gas power generation industry is already formed by the existence of gas suppliers and power generators whose roles are now clearly defined in the new Power Industry Reform Act.

Virtually without gas market so far, however, there has been no gas downstream distribution entity well established to handle the Camago/Malampaya gas or any gas from other sources for direct distribution yet. Who will actively proceed with various aspects of the gas business in the downstream is not clearly seen as of summer 2001 when gas industry is said to start in a few years. First Gas Holding has been awarded the franchise to transmit and distribute gas in Luzon area by the RA 8997 and is expected to proceed with the network and market development. Existence of a proactive local sponsor will be key to the development especially in the Philippines where foreign participation is constitutionally restricted in this sector.

It is appreciable that First Gas Holding is financially and technically able and willing to lead the downstream development; otherwise, however, we would comment that certain government's involvement in investment as well as regulation is still common in the infant stage of infrastructure development. Full deregulation and privatization may be the best in matured markets only in developing countries without financial strength. Forced unbundling of pipeline and distribution may be unnecessary on an infant stage of development when integrated business income will sustain the overall capital structure of a project.

(6) Business Buildup Procedures and O&M

There have been no definite procedures established for gas utility market entrants and investors. The Team understands that DOE is preparing for necessary procedures and forms after the recommendation made in the ADB Study. In the current regulatory environment characteristic to the Philippines the actual experiences of the business pioneers are expected to pave the way for establishing de facto procedures until the promulgation of official procedures.

(7) Technical Regulation

The DOE intends, the Team understands, to establish the technical standards for gas pipelines, relevant facilities and work practices initially following US Department of Transportation (USDOT) / Office of Pipeline Safety (OPS) Codes (49 CFR) and National Fire Protection Association (NFPA) 54 as the ADB Project Report recommends. The codes in the 49 CFR, for example, give minimum technical standards covering most of the transmission and distribution business areas.

Only notes to be made here is that actual gas business entities in other countries often add stricter standards to protect their business and also that the US DOT codes are frequently updated. Citing the 49 CFR in other country's standards, therefore, has to specify which year's version is being adopted, or otherwise the contents should be better rephrased to suit to that country's industrial standards system. The US codes will be a good model, notwithstanding, for starting with a technical regulatory system for pipelines. The system should be flexibly maintained according to the actual conditions and experiences in the Philippines, and application of comparable standards employed in other countries should be permitted, too.

The DOT/OPS and NFPA standards are basically intended for safety. There are other technical standards to be adopted for, e.g., commerce and customer's safety purposes, as well as efficiency, which will be prepared step by step in accordance with the market growth. General rules of business inception and pricing of interstate pipelines in the US are issued by the Federal Energy Regulatory Commission (FERC), but gas distribution companies are regulated by the public utility commission (differently named from state to state) of each state and somewhat differently. A small additional study may be necessary to create gas distribution rules.

3-1-3 Existing Comments Regarding Gas Regulation

(1) Reviewing ADB Recommendations

The Report of the Asian Development Bank (ADB) in 2000 on the "Gas Sector Policy and Regulatory Framework Project" has already examined most of the legal and regulatory issues stated above and recommended detailed energy regulatory reforms to the Government.

The Team endorses ADB's address that the policy criteria for the overall gas industry, more focusing on up- and mid-stream, should be set in the principles of:

- Accountability – e.g., issues are behind due to fragmented authorities,
- Participation – more participants in the policy process,
- Predictability – i.e., confidential arrangements prohibits outside prediction,
- Transparency – i.e., procedures on permits, rate setting, are not clear,
- Autonomy – decision making under fragmented authorities often taken up by President, agencies losing autonomy,
- Clarity – e.g., ERDB roles in the upstream is not clear enough,
- Feasibility – allowing conditions for project feasibility etc.,
- Sustainability – sustainability of gas industry is uncertain under the current conditions, use of gas for other purposes than power generation being forgotten, and
- Stability –necessary to establish stable and competitive environment.

(2) Comments on Regulations from the Gas Industry

Our hearings from actual and potential sponsors for the Philippine gas industry suggested several points of uncertainties and issues as:

- The right of way for transmission pipelines was prohibitively expensive to obtain in a case due to the land ownership system and lack of penetration of the eminent domain concept in the private sector business society.

- Production sharing type of upstream concession right specifies royalty and a 60/40 government/developer shares. The royalty is comparatively high and effectuates as an eventual unduly leveraged tax on gas, which loses competitiveness against other fuels.

- While gas promotion policy is there, means of obtaining construction permits on various steps are uncertain. Also technical standards to be applied to the facilities are not specified.

- There is no method legally specified to set the gas transmission and distribution prices while regulated tariffs are officially controlled by ERB.

- A gas distribution franchise (then for manufactured gas) was given to Manila Gas Corporation in Metro Manila by Congress legislation, physical facilities for which (gas pipe networks) are not currently used as the concession being still retained, while the Company distributes bottled LPG there. There is no legal steps specified how to handle this unused franchise for the future potential gas distribution.

- LNG import is potentially taxed at a rate of 10% (5% from 2003) by the national customhouse code, to safeguard the competitiveness of pipeline natural gas from the Camago/Malampaya field.

3-1-4 Effect of Electric Power Reform Act on Gas

The new Electric Power Industry Reform Act of 2001 has been installed since June 8, 2001, becoming effective two weeks later. The Act includes the temporary assumption of the financial obligation of NPC not exceeding Two hundred billion pesos equivalent to approximately US$5 billion before the breakup of NPC. The enactment of the Act has long been sought from international financial community as a condition of public borrowing from financial institutions and various international commitments.

The Act, progressive for the free market principle, seems to contain certain effect on gas, since both electric and gas markets are on the public energy utility ground. We have to be careful, however, on the difference between the two in the Philippines.

One is the difference in maturity of the market as already discussed elsewhere. Although there are still 20 % of remote barrangays without access to electricity (as of 2001), due to the country being an archipelago, electricity is already prevalent in all populated lands with established infrastructure and market in the country. On the other hand, gas is virtually in future market where much investment in infrastructure is needed from scratch.

The other difference is in competitiveness. Gas and electricity are competitive with each other in heating and air-conditioning. For lighting and mechanical /electronic use market, electricity has no competitor and it is a civil necessity for every person. While gas is surly useful, it always faces competing fuels like LPG, wood, kerosene and diesel. From this point of view, the regulation could be different between gas and electricity. While the gas network is publicly important, its business is not a natural monopoly any more for the most part of the market.

Gas could penetrate competitively only in high-energy consumption density areas where the cost of distribution per customer is minimal and consumption per customer is comparably large considering the Philippine climate. If an obligation is levied for strict non-discriminatory distribution in the franchised market as is declared in the Power Reform Act, the gas business may fail. Virtual preferential customer base may have to be permitted for beginning gas distribution in an initial stage. The scope of viable "captive gas customers" is very limited in the Philippines unlike matured northern industrial countries.

While differences are such as stated above between gas and electricity, there will be cases where gas and power sectors have to be combined, raising conflicting issues. There is already a question raised onto whether the gas just downstream the Batangas gas processing plant is "piped gas" and the "petroleum" defined by the Petroleum Act of 1949 or the "oil" stipulated in the Downstream Oil Deregulation Act of 1998, involving an inter-departmental power issue. The question in Batangas was overcome by defining the pipeline to the power station as a part of the power station, which is not a public utility.

How will the gas from a future LNG terminal to a power plant be handled then? First, the LNG terminal will be a refinery under the Downstream Oil Deregulation Act of 1998, so that foreign partners can play a role. If a gas pipe is installed from a terminal to, e.g., an 18 km (11 miles) distant power station, partly foreign owned and operated, and a branch line is extended from on the way to a separate gas distribution area, most part of the pipeline will be a public utility which is subject to non-discriminatory open access while enjoying power of eminent domain. Which bank will finance the pipeline without firm commitment of completion and use is potentially a headache issue. DOE's IRR should be flexibly established to accommodate virtual exclusivity and a power of eminent domain to satisfy the business sponsor's and financiers' need.

When gas power generations are important customers of the gas transmission and distribution network as well as industrial and other gas customers, a power generation could be located at an end of a pubic utility pipeline in the future. Such power generation might be a high-efficiency co-generation suitable to urban areas, enabled only by the clean fuel, natural gas. This raises the economic efficiency of the pipeline by increasing the capacity use. Often such a power generation will be located at a strategic point in proximity to a large demand area instead of a remote village. This power generation has to pay the gas pipeline cost, but considerably saves the power transmission cost and also avoids the power transmission loss by several percent, compared to a case of remote village power generation. The comparisons of integrated cost and efficiency will be easily calculated to in an actual case.

A concern here is how such power generation will be dispatched into the market by the power transmission pool of the TRANSCO and the wholesale spot market to be created by the new Power Reform Act. If the dispatch is based simply on the price of the power per kWh, regardless of the location in the power transmission network, such higher efficiency generation may lose competition. Some kind of merit valuation factor should be incorporated in the power bidding system to encourage promoting integrated economy and efficiency. "Energy transmission by a gas pipeline or by power transmission?" is a worldwide topic in the current energy world and a likely answer seems in the gas pipeline in view of high overall efficiency when other conditions are same.

This debate affects the destiny of the site of the Sucat power station. They should think about which is a more efficient form, gas or power, when energy is to be transported to the large Manila demand area from Batangas.

Another concern is how gas power generation will be dispatched compared to other power generations. Gas power is the cheapest of the power generations in general regarding the total long-term economic cost, but this is largely due to lower capital cost and high efficiency as well as lower environmental cost of the combined cycle system and a proper gas price. The fuel cost of gas power solely depends on natural gas purchase price and its price is not necessarily lower than heavy oil or coal on the thermal basis. This comparison is demonstrated in Tables 3-1-1 (a), (b) and (c), which show breakdowns of the economic power generation costs as well as gas netback values, where assumptions are on the part (a) and results are on (b). The part (c) demonstrates a sensitivity analysis regarding discount rates. The values in this table are in real terms only, i.e., not assuming inflation, and not linked to any other projections in the JICA Study, and is only for discussing the typical cost differences among power generations here.

Based on the tables, the gas power wins the competition in terms of the overall levelized average cost per kWh but may lose on the combined O&M and fuel costs, which normally is the running cost, against coal, hydro and geothermal. Once investment has been made in a plant, a weight in economic consideration somewhat shifts and they tend to compete simply on the running cost to cover the immediate cost, forgetting about the nature of financial repayment and future replacement. The merit to the benefit should be compared based on a fare ground of the total economic cost and social/environmental benefit in the power bidding. The power pool bidding process should be so designed.

Table 3-1-1 (a) Potential Power Generation Costs in the Philippines - Assumptions

Typical Power Generation Costs and Gas Netback Values Compared

Write in plant number below for recaculation

Starting year=	2001		Local Currency = Peso
Select TARGET PLANT code=	3	is the main plant selected for planning.	Peso /US$ = 52
Your GAS PLANT code=	2	is brought in to find fuel netback value.	

		Plant Code		1	2	3	4	5
		Plant Type:		Steam Turb. w/ FGD	Comb. Cycle Gas (C.C.)	Coal Power	Geothermal -	Hydro -
		Fuel :		Fuel Oil	Natural gas	Coal	-	-
Part 1		Fuel trade unit:		bl	mmBtu	ton	GWh	GWh
	Input - Technical Assumption		Unit					
	31	Installed capacity	MW	500	500	300	60	200
	32	Load factor	%	70%	75%	70%	60%	35%
	33	Thermal efficiency (gross based)	%	36%	45%	38%	100%	100%
	34	Construction Start Delay	Year	0	0	0	0	0
	35	Construction period	Years	2.0	2.0	2.0	2.0	5.0
	36	Project life and operation years*	Years	20.0	25.0	25.0	20.0	20.0
	37	Physical economic life of plant	Years	25	25	25	40	35
	38	Period till plateau reached:	Years	3	3	3	3	3
	39	Power output from Other? (No only - future use)		no	no	no	no	no
	40	Hours in a year	Hours	8760	8760	8760	8760	8760
Part 2								
	Input - Economic Assumption							
	41	Real interest (discount) rate	%	12%	12%	12%	12%	12%
	42	Investment cost per capacity	US$/kW	1000	650	1800	2800	1400
	43	Other ancillary investment	US$000	0	0	0	0	0
	44	O & M fixed cost factor (yearly)	% of Capex	3.00%	2.50%	3.50%	1.5%	0.6%
	45	O & M variable cost factor (yearly)	USc/kWh	0.100	0.050	0.070	0.030	0.010
	46	Current fuel price ($/trade unit)	$/Unit	25.00	5.00	33.00	0.00	0.00
	47	Escalation on Fuel price	%/year	0%	0%	0%	0%	0%
	48	Gross heat value of fuel (mmBtu/Fuel unit)		6.1808	1	23.500	3412	3412
		Fuel Price:	US$/mmBtu	4.045	5.000	1.404	0.000	0.000

Table 3-1-1 (b) Potential Power Generation Costs in the Philippines - Results

Part 3 Summary Results		Target plant code	1	2	3	4	5
Power Generation Cost			Steam Turb. w/ FGD	Comb. Cycle Gas (C.C.)	Coal Power	Geothermal -	Hydro -
	Levelized Average Cost:	USCent /KWh	**7.04**	**5.62**	**6.93**	**9.04**	**8.77**
	ibid:	Peso/kWh	3.66	2.92	3.60	4.70	4.56
of which	Capital Cost	%	36.3	26.7	64.1	89.7	96.4
	Fixed O&M	%	7.9	4.9	16.6	10.0	3.5
	Variable O&M	%	1.4	0.9	1.0	0.3	0.1
	Fuel Cost	%	54.5	67.5	18.2	0.0	0.0
	O&M and Fuel Costs	Peso/kWh	2.33	2.14	1.29	0.49	0.17
Natural Gas Netback Value							
For	Comb. Cycle Gas (C.C.) -pres val.	$/mmBtu	**6.88**	**5.00**	**6.73**	**9.51**	**9.15**
Code= 2	Same in GJ	$/GJ	**6.25**	**4.55**	**6.12**	**8.64**	**8.32**
	Same in	Peso/10,000 kcal	14.19	10.32	13.89	19.62	18.89
	2001 Currnt value	$/mmBtu	6.88	5.00	6.73	9.51	9.15

An interesting nature of the comparison is demonstrated in the sensitivity analyses shown on the part (c) of Table 3-1-1. Private sector investors for power generation normally requires an IRR (or discount rate) of 12% or more, but use of low interest loan can considerably lower the overall discount rate which decreases the generation costs in capital intensive plants. Hydro, geothermal and coal power are more capital intensive plants than the gas power, and the analyses show how more those plants produce lower costs. If these powers had been publicly financed with lower interest or with higher grant element, they will be very competitive. Other powers will have to seek ever-lower interest financing facilities for new plants to compete. If a country too much rest with low interest public loans effectuating low power tariffs, however, the industry will face difficulty in future replacement of the power plants when more private sector principles prevail. Comparative high power tariff, which Filipinos often complain about, is in fact a source of viability of the future power industry since more economic rent will finance future infrastructures.

Table 3-1-1 (c) Potential Power Generation Costs in the Philippines - Sensitivity

Sensitivity Analyses

1. Effect of discount rate on the generation costs 1			2. Effect of discount rate on the generation costs 2		
		Cent/kWh			Cent/kWh
	Geothermal	Hydro		CCGT	Coal Pwr
D. Rate%	9.04	8.77	D. Rate%	5.62	6.93
4.0%	4.18	3.46	4.0%	4.78	4.44
6.0%	5.28	4.57	6.0%	4.96	4.97
8.0%	6.45	5.82	8.0%	5.16	5.56
10.0%	7.71	7.21	**10.0%**	5.38	6.22
12.0%	9.04	8.77	12.0%	5.62	6.93

The Power Reform Act, Sec. 34, specifies equalization of taxes and royalties in favor of indigenous and renewable resources, to be an element of the so-called universal charge. This is also viewed as to establish an adjustment in equal footing in power generation dispatch competition. We understand that a trust fund will be created to receive a part of fund from the universal charge to be used for the purchase cost of power based on the imported energy for a stabilization purpose. This will hopefully work for a benefit in stabilizing the power rate when power demand increases and use of high cost imported oil or gas could not be avoided.

3-1-5 Energy Price Systems and Situations

While selling gas to a power generation is such as described in the above paragraph, the promotion of natural gas in the gas sector is directly affected by the gas purchase price competition as well as the network costs.

Recent Philippine energy prices in potential competition with future gas are picked up in the Table 3-1-2. The instant prices cited here are simply for inter fuel comparison and may not agree to those in other chapters due to the difference in sources and unit conversion process. Oil product prices in Peso terms was increasing depending on the rise of international crude oil prices and progressively weaker exchange rate until 2000, although competition has suppressed the rise in prices to an extent. International oil prices in the background has dramatically changed in this period as in Figure 3-1-1 and Figure 3-1-2, affecting Philippine prices. The natural gas price at Tabangao is linked to several factors but not 100% linked to crude oil and so gas may be becoming more competitive. LNG import prices, not relevant to the Philippines in the past, depend on negotiation but normally linked to crude oil prices on thermal values in Northern Asia so far. Discussions are prevalent on lower LNG prices expected for the future. Price competitiveness of gas depends on the pipe network construction and operation costs while the allowance may not be large.

Philippine oil prices were deregulated by the RA 8479 of 1998 and market prices now prevail. As most crude oil and petroleum products are imported, the product market is affected by international prices with a buffer of several petroleum refineries located mostly on Luzon Island and other small stock terminals. Oil here includes LPG but not piped gas. The major petroleum industry consists of Shell, Texaco and Petron (partly owned by PNOC) having refineries. After the deregulation more companies are coming in the market for importing and trading petroleum products. Especially LPG is now traded by National Gas (Chinese), Liquid Gas (European), Total (French), Pryce Gas (Taiwanese) and Petronas (Malaysian) in addition to the existing three (3) major enterprises, thus promoting competition.

Table 3-1-2 Recent Philippine Energy Prices (Commercial use)

				Market Price in P/liter (or kg)***				Price interpreted in US$/MMBtu			
	Thermal value (gross)	Excise tax	Import tariff**	Jan. 1998	Dec. 1999	Dec. 2000	Nov. 2001	Jan. 1998	Dec. 1999	Dec. 2000	Nov. 2001
	kcal/l (or kg)	P/liter	%				****	Forex 39 P/$	Forex 40 P/$	Forex 49 P/$	Forex 52 P/$
Premier gasoline	8,580	5.35	3 (0)	10.8	13.6	17.8	17.4	8.14	10.01	10.69	9.82
Unleaded gasoline	8,427	4.35	3 (0)	10.5	13.3	17.3	16.7	8.04	9.91	10.55	9.64
Regular gasoline	8,427	4.80	3 (0)	9.0	12.0	16.3		6.87	8.95	9.98	
Kerosene	8,753	0.60	3 (0)	5.8	8.6	13.1	13.3	4.27	6.16	7.70	7.37
Diesel oil	9,281	1.63	3 (0)	7.2	9.3	13.6	13.5	5.01	6.29	7.54	7.06
Fuel oil	10,007	0.30	3 (0)	4.7	7.8	11.6		3.05	4.93	5.98	
LPG (P/kg)	12,000	0	3 (0)	10.9	9.0	10.6	12.8	5.85	4.71	4.55	5.18
Gas * /Tabangao	9,780	2%	3%	-	-	-	-	-	4.00	5.00	
LNG*	10,500	2%	3%	-	-	-	-	3.25	3.65	4.75	4.35

Note: *Gas: kcal/T (gross)/m³; Price: US $/MMBtu; LNG: CIF Japan less (-) 25 US Cents/MMBtu, indicative only

** Import duties for oil products are temporary exempted since November 2000 by PD314.

*** 1998 and 1999 domestic prices derived from ADB study; 2000 derived from MEMSI report.

**** Nov. 19, 2001 Average of pump prices cited in DOE home page; Dealers' pick-up price for LPG.

(Source) JICA Team / MEMSI study 2001 / DOE 2001

Electricity tariffs to end customers are regulated by the ERC (formerly ERB). On the wholesale level, however, power generation prices will be determined by negotiations between the generation company and an off-taker, i.e., TRANSCO or a distribution company, and accredited by ERC. Some of basic rules are that existing formulas are based on the "cost plus" method, amount of functional asset based, allowing inclusion of 2 month operating fund into the rate base and the return of 12 % against effective asset for a private sector utility and 10% for a publicly operated utility.

The Philippines has been used to the international level of energy prices, while some people complain about high prices and effort is always necessary to decrease prices for maintaining consumer's international competition. This is compared to the fact that many countries with a policy of intentional low energy prices are having difficulty in upgrading energy infrastructure without ability to draw the necessary cash flow from the prices. Certain higher energy prices we hope are a national asset and will bring about benefit through economic growth.

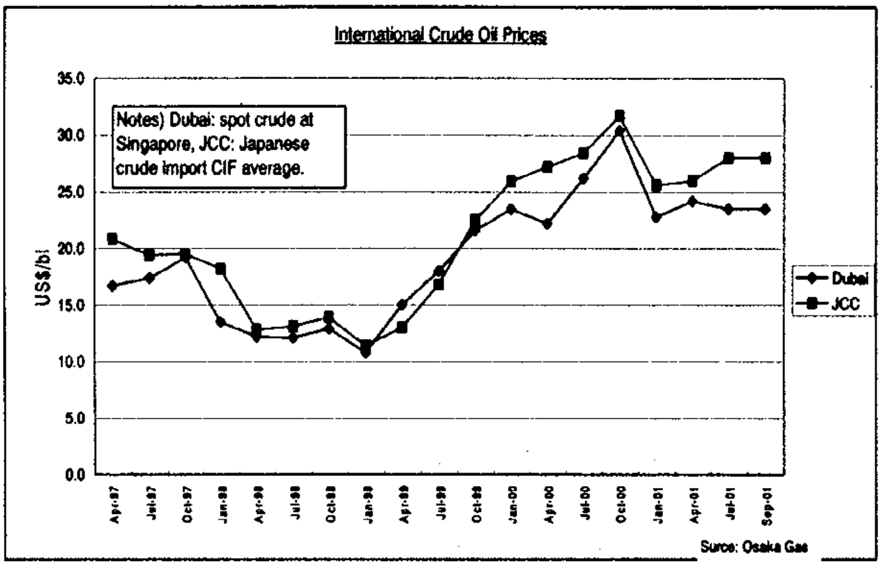


Figure 3·1·1 Recent International Oil Price Trend

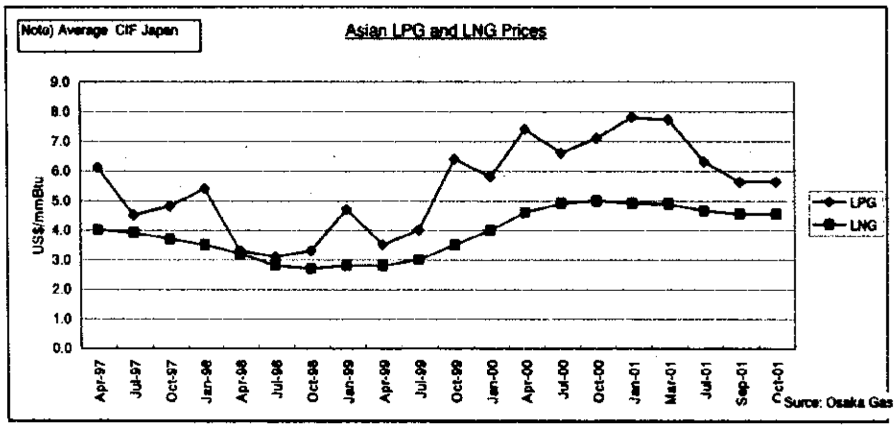


Figure 3·1·2 Recent International LPG and LNG Prices

There are no general rules or formulae on gas prices except in the upstream. The prices of gas from the Camago/Malampaya field at Tabangao landfall to power generations, however, are set with international formulae shown elsewhere. The Prices are heavily affected by the share percentage (currently 60%) of the "government take" or a kind of royalty in the gas field development, which, a little too high, could be adjustable for the industry to get a lower electricity tariff in the near future.

The gas industry heavily depends on pipeline facilities where economy normally requires to carry gas for large customers like power generation as well as large industrial customers in early stages due to a high unit gas cost to smaller customers. How electric development side will respond to this nature of gas industry seriously affects the pipeline development. Gas is clearly preferable for power generation in view of the electric cost and efficiency as well as environment, and it is also preferable for a pipeline to be able to transport gas both for generation and direct use without problem.

For gas markets other than to power generation and large industrial customers, gas has to compete with those fuels after adding the network cost, connection cost, customer's cost and market promotion costs. One most important way to minimize the costs initially is to select the most suitable clusters of customers. The conditions for preferable clusters are:

1) High energy consumption areas included
2) Affordable market areas - relevant to income level and gas consumption
3) Proximity to main gas pipes - to decrease the cost of distribution mains and branches
4) Large commercial customers included in the market
5) High housing density - to lower the per-customer costs of grids
6) Gas air-conditioning possibility (commercial facilities to be newly planned)

Before marketing, how we get lower cost gas will be the first matter. We have choice among Camago/Malampaya with its potential expansion, Trans-ASEAN pipeline and LNG. The former is already in and must be best utilized, but the growth of the Philippines will need more gas than it could supply during our Master Plan period. Therefore, which is cheaper, the Trans-ASEAN or LNG, is a question that will be addressed. In the JICA projection, we assume two LNG terminals in the Luzon area earlier installed due to projected demand and Trans -ASEAN later, around 2015, on the preliminary basis. A serious selection will have to be separately studied.

LNG or Piped Gas?: Which is cheaper, pipeline or LNG, for international long haul transportation of gas requires detailed examination, while we could make a provisional comparison on estimated economic costs for imaginable gas sources. Purely physically, a cross point where the long haul transportation cost becomes equivalent between pipeline gas and LNG is generally in 2,000 to 4,000 km of the transportation distance as generally said. A sample comparison is demonstrated in Table 3-1-3 (a)- Assumption and (b) –Results, and Figure 3-1-3.

Tables 3-1-3 (a) & (b) show assumptions and results for and of model economic cash flow calculations. Computations of economic costs are made in real terms only without assuming inflation. Costs of LNG here covers the LNG chain from liquefaction up to re-gasification. Pipeline costs include US$100 million gas processing facility and the both counts on US$10 million preparation study. A nominal (US$0.5 /MMBtu) wellhead price is added on the both.

Table 3-1-3 (a) A Cost Comparison of LNG and Pipeline Gas – Assumptions

Assumptions

1. Physical Assumptions:

Assume off-shore transportation for both

Distance (Base Case):	1450	km
Gas quality	10161	kcal/Nm3 (0dC)
or =:	1080	Btu/Mscf = 40.33 MJ/m3(15C)
LNG liquid density	0.45	t/m3
Transport Capacity:	3	mta
=	381.1	mmscfd (15.5dC)
=	3.724	bcm/y (0dC)

2. Financial Assumptions:

Project begin:	2001	year
Period:	25	years
Discount rate:	12%	
Physical life:	35	years
Taxes & inflation:	neglected	
Case 2:	3	million tons /yr. (mta)
	381.1	mmscfd (15.5dC)
	3.724	bcm/y (0dC)
FS or Preparation Costs:	10	$ million to either

3. Pipeline Conditions: Base case

Pipeline Pressure (Max):	80	bar
Pipeline Pressure (Min):	55	bar
Initial Press.:	50	Final Pr.: 40
Distance btwn Compressors:	500	km
Compressor Stns.:	2	stations after initial
plus last section:	450	km
Construction yrs.:	3	years
Demand buildup yrs.:	4	years
Pipeline Cost:	35000	US$/km/inch
Compressor Cost:	1200	US$/HP
Major pipe size:	30	inch
Compressor Size:	11,172	HP
Other conditions: Gas processing:	100	mil. US$

4. LNG Conditions: Base case:

Liquefaction Capacit	3	mta
	Cost scaling: (X1/X2)^0.75+fixed term	
LNG ship capacity:	135000	m3 (kl) = 60,750 t
	Cost= Capacity (kl) x A1+ B1	
	Speed 19 knot, Loading + unloading: 25 hrs.	
	Dry Dock: 40days/2.5years	
Receiving Storage :	2 tanks x 135,885 kl	
i.e., Ship Capacity+ 7days + dead 10%		
	Cost= Storage cap (kl)x A2+ B2	
O&M Costs:	Fixed and variable costs	
Construction:	3	years
Ship Build up:	4	years

Table 3-1-3 (b) A Cost Comparison of LNG and Pipeline Gas – Results

Results

Costs Summary:

1450 km	Economic	Capital Cost (NPV)	O&M Cost (NPV)	Total Cost (NPV)	Unit Gas Cost
3.00 mil. ton/y	Costs	US$million	US$million	US$million	$/mmBtu
Long term cost:	LNG	1,478	523	2,001	3.263
Ave. levelized costs)	Pipelines	1,890	218	2,108	3.255

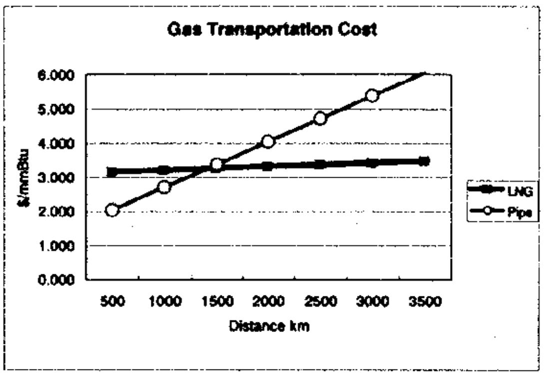
Unit Gas Cost Breakdowns:

LNG:	$/mmBtu	Pipeline	$/mmBtu
Wellhead	0.500	Wellhead	0.500
Liquefaction	1.922	Gas field	0.129
Shipping	0.282	Transmission	2.626
Regasification	0.559		
	3.263		3.255

Figure 3-1-3 shows the effects of the distance on the economic costs based on the typical model calculation and on the same conditions shown by the Table above except for distances.

Gas Transportation Cost vs. Distance

3 million tons/y = 381 mmscfd



Capex vs. Distance

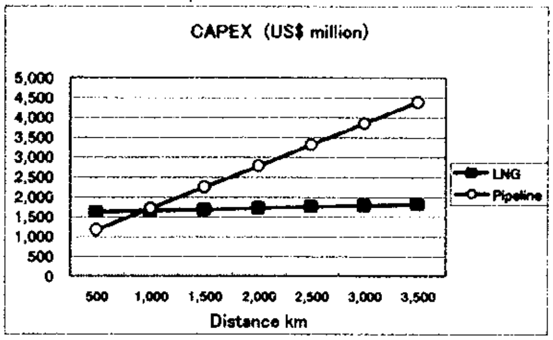


Figure 3-1-3 Effects of Distance on the Costs of LNG and Pipeline Gas

Actual costs will be different from these demonstrated due to diverse conditions from place to place. The pipeline cost estimate here, for example, is based on a single pipeline, but actual design might require a loop or a double pipe system resulting in much higher cost. Theses calculations, in fact, are an indicative only and recent significant trend of plant cost cutting may not be fully counted on. Actual prices will depend further on many factors including specific markets and international negotiations. Which is easier to materialize to meet future demand projections is another matter to be considered with other factors including security, etc. Pipeline basically needs more international negotiations with involved countries and more local discussions for securing the right of way. When it passes a third country, the transit fee issue is normally a tough one to be negotiated taking much time.

Nevertheless, if the Trans ASEAN Pipeline for the Philippines assumes a gas field in Sarawak, Malaysia, as a supply source about 1,500 km distant from Manila, as we occasionally hear, the Figure suggests that the physical pipeline transportation cost may be comparable or a little lower than the overall cost of an LNG scheme, based one pipeline design. But the physical cost is only an element in a project. Sellers, e.g., will be looking at what is the value of the gas in the Philippine market and the difference in the cost, a surplus or economic rent, may not necessarily be brought in to the Philippines. For international negotiations and financing we just think how many years has passed until the inauguration of the Camago/Malampaya gas as well as what the actual gas cost is.

On the other hand LNG has already markets in Asia and many supply sources will be seeking new markets in the first decade of 2000s. The scheme of LNG projects may be simpler and clearer than international pipelines. We have to wait for what prices they will offer and what kind of financing will be possible in the Philippines. Financing normally requires multilateral relationships.

3-2 Policy and Institutional Measures for Gas Use Promotion

3-2-1 General Focuses in Planning Gas Use Promotion

(1) Upstream – Promotion of Smaller Resources

The gas industry promotion has wide implications since the upstream, mid-stream and the downstream have respectively different business nature.

The development in oil and gas upstream, as well as a part of mid-stream, including gas supply to power generation, has long history in the Philippines over three decades already and has now reached the dawn of start-up of the gas industry, necessitating a long term perspective of the industry to be drawn up. To be consistent, our discussion on the promotion policy in this Study is to mainly cover the mid- and downstream of gas based on the proven potential of the gas reserves and supply. Nevertheless we will briefly review the upstream and consider measures for use in case of any renewed effect on the whole gas promotion and down stream.

The Master Plan bases discussions of the indigenous gas supply only on the proven reserves of the Camago/Malampaya and San Martin gas fields, together defined as approximately 3.0 TCF (trillion cubic feet at 60F, equivalent to 80 Normal billion cubic meter, or 72 million toe as of the gas quality of 9700 kcal/Nm3 or 1031 Btu/scf). The potential reserves of these fields are deemed as up to 4 TCF. Detailed breakdowns of the above and other gas resources are described in the next Chapter (See Table 4-1).

Other gas fields, however, draw attention, too, since energy security through development of indigenous resources has long been on national agenda. Some are proven with a small amount and others are not proven yet but with large prospect according to PNOC-EC, which aggressively proceeds with the missionary development. Special attention is given to the following upstream projects in view of the use of the gas resources:

San Antonio Reservoir: Located around Santiago City, Cagayan Isabela Province, about 240 km north of Manila, the South Cagayan (SC37) field seems to have a potential of 320 BCF of natural gas. The current estimated reserves are 4.3 BCF based on the down hole survey. There is a production of 1 mmscfd capable of generating 3 MW at the mine-mouth, representing a national monumental project of local natural gas use in the country. The missionary capacity of the test power plant could accommodate about 15,000 families, comparable to a local city. This surely contributes to the foreign exchange saving for yearly oil purchase by US$600,000, setting aside the plant cost. The operation will continue until 2008 when the commercial plan will be formulated.

Offshore Mindoro: The "GSEC 88" gas field is located in the southeast offshore Mindoro with a prospect of 1.8 TCF of natural gas. The area is close to the Camago/Malampaya gas pipeline and therefore the field could be seen as an important successor to the current gas sources.

Cotabato Basin: The "GSEC 73" gas field, 80 km south-east of Cotabato City and 90 km west of Davao, Mindanao, is expected to contain combined recoverable reserves of 600 BCF equivalent to 82 million bbl of oil. Of the Basin, 200 BCF of gas are from shallow and water resolved gas deposits. The gas is lean at 8100 kcal/Nm3, or 860 Btu/scf. Of the Basin, the Sultan-Sa-Parongis Prospect has estimated recoverable reserves of 60 BCF, which is a source of PNOC's plan for a 60 MW CCGT power plant. PNOC-EC plans to drill three (3) more wells in the basin.

There is information of unconfirmed gas potential in the area of Tarlac, 100 km north of Manila. Possible development of the gas there will depend on the size of gas find. If it is large, combined use for power generation and thermal purposes will be efficient. Power generation of too small a size, instead, will be costly on the thermal unit basis. The area is within potential vigorous urban and industrial development plans. A possible way of use of that smaller gas, if it is really smaller, will be to use it as a primer of gas distribution network, which will be connected to the future large pipes being expected to come from the Manila area.

There are further activities in southeast Ragay Gulf and Cebu areas, while information on the Ragay Gulf exploration off southern Luzon Island, which is appreciatedly located comparatively close to NCR, is still waited for.

In Cebu, PNOC-EC has 2 BCF of proven gas reserves at 90 km north of Cebu City and local business groups are contemplating use of the gas for power generation. A simple calculation shows that a 1.7 MW power generation using this gas might cost US$1.4 million (plant only) approximately and save US$400,000 (at US$22/bl) of annual crude purchase. If the gas were delivered by pipelines to nearby 12,400 residents, using 18 Nm3 monthly, 2,100 t of LPG, or US$430,000 at US$200/t, could be annually saved, setting aside pipe costs.

For the Master Plan, unfortunately, all of this smaller gas finds are geographically too distant from the designated scope of work areas and gas reserves are not fully proven to be directly counted on into the gas supply projections. These gas finds, however smaller instead, add to the missionary aspiration of national gas use promotion and are important.

Small gas fields have been effectively used somewhere elsewhere. In Japan, gas fields in Niigata area on the Japan Sea side, 300 km north of Tokyo, and the marsh gas (water resolved gas) fields in Chiba area, east of Tokyo, formed early natural gas industry long time ago. Gas has been used for rural distribution for residences and became primer for larger gas utilities of today. The gas in those areas being depleted, the distribution networks are now connected to the pipelines from LNG terminals. Cases of inexpensive rural gas distribution have been heard from Canada, too.

For another option, we could wait for more technology development of the gas-to-liquid (GTL) process, now widely discussed in the world. There is news that the cost of the process will lower in the future, when smaller plants might be economical. In contrast to the traditional Fisher-Tropsch process for liquefaction, the "Dimethyl Ether" production system is said to be more easily adaptable to smaller sizes as described in Chapter 4-6 of this Study. When this becomes economical, such gas may be used as liquid for vehicles without pipelines. Currently, however, the product seems still expensive.

(2) Infrastructure and Downstream Market Promotion

(Gas Development Principles)

While normally sales promotion means market promotion, a gas market only exists where there is gas network. Gas use or sales promotion must mean both the promotion of gas network development and strategic gas sales promotion within a promoted business environment framework. More broadly saying, the "gas development" can be accomplished only when all sectors of upstream, pipelines, distribution and the market are developed in a synchronized way. The upstream needs a market and a market needs supply from the upstream and pipelines. Both the infrastructures have to be developed together as in Figure 3-2-1.

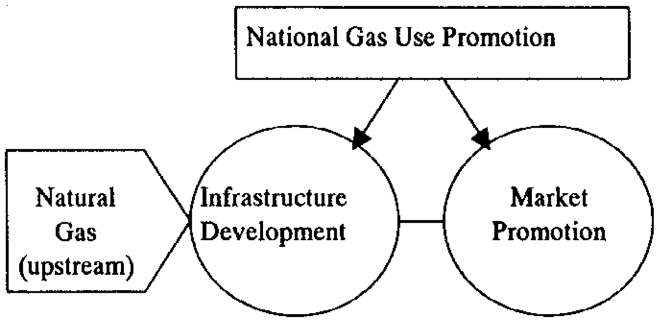


Figure 3-2-1 Both Infrastructure and Market have to Be Promoted Together

Looking at how gas distribution network and market were developed in an initial stage in other countries, we find very few or almost no cases of the network development without government support except in 1800s or early 1900s when (manufactured) gas was used for lighting with a very high market value. In modern years, many developing countries have supported gas distribution network development in their major cities mostly with government bodies, while private sector style management has been introduced after certain maturity is accomplished. Private sector gas network development is still comparatively new now in developing countries. It is a financially difficult area for private sector without assured collateral like power purchase agreement in the power sector for financing but with revenues only from the tariff system which may not be deemed sufficient by financiers until a pipe network and the market are matured and a stable cash flow is established. For a purely private sector business, a strong sponsor may have to participate and offer a corporate guarantee but there may not be many such companies in the world.

(Downstream Development Practices in Various Countries:)

Looking at market economies familiar to and around the Philippines, the gas transmission and distribution promoters have been national companies in Indonesia, Singapore, Thailand, Malaysia, India and Pakistan. Some are considering privatization based on the infrastructure established to certain extent. Hong Kong is an exception where a purely private sector company operates and high city gas cost is accepted by affluent customers as well as high consumption density exists. In more remote tropical or semi-tropical countries[2], e.g., Egypt, Tunisia, Algeria, Colombia and Trinidad, national companies operate the gas downstream sectors, while again some are considering privatization. These countries are even gas rich countries. Gas lean countries clearly need an extra public effort. This exemplifies that a strong government lead is necessary for building up the infrastructure. A government has often two roles, national investor and regulator to avoid market abuse. Promoted use of private sector motivation and management for public infrastructure projects should not mean to leave everything on the private sector.

Thailand demonstrates a typical example of government's involvement in gas use development. The nationally owned Petroleum Authority of Thailand (PTT), partly listed in the stock exchange, has been a strong investor in the oil and gas sector including downstream. PTT is qualified, as a national company, to use loans from international public financial institutions. It owns main transmission pipes and negotiates gas prices with international oil companies in the upstream. It has formed joint venture businesses for a gas network for industries and plans a capital loop transmission line in a form joint venture with private sector inventors. Thus the strong initiative for gas promotion is still held by a government body. Gas regulations and policies are set by the Ministry of Industry and the National Energy Policy Office respectively independently from PTT.

Even in industrial countries, while movement is toward deregulation and privatization in any country, many governments have been directly helping transmission pipeline networks since they are beneficial to the nation but are not or should not be necessarily too profitable for investors. They have been undertaken virtually either by nation or by current or former national corporations in France, Britain, Italy, Spain, Portugal, Greece, Denmark, Ireland, Canada, Austria, Belgium, Sweden, Turkey, Australia and all Former Soviet Union and Eastern European countries, with a few exceptions. Privatization or other competition promotion measures has occurred only after establishing matured networks. In case of private sector dominated development, large enterprises comparable to a national corporation have been involved in Germany, Holland and New Zealand. Exceptions are US, which is rich in domestic gas reserves and financial resources, and Japan, where there is virtually no transmission pipelines without any governmental help. In most countries, virtual monopoly exists.

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[2] Examples in other countries are known from several reports in 21st World Gas Conference, Nice, June 6-9, 2000

Type of ownership and management for gas distribution networks are varied from country to country. In some countries such networks are still managed by the nation, as in France, but in others, provincial government, private sector entities and/or their combination companies own and operate the networks under regulatory framework. The most long-time and widely privatized management is seen in the US and Japan, even where there are many municipality owned gas utilities, without any direct public subsidies. In the UK, British Gas (BG) used to have monopoly in gas pipeline and distribution business in the country, underwent privatization in late 1980s and has been unique in progressive unbundling after the Gas Act of 1995, with fully saturated gas networks and market. The UK has been presenting the world an extreme model for enhanced competition, insisting on 30% lower prices to the public customers, partly thanks to lower oil prices in the same period, as well as certain deteriorated services and complaints.

Argentina, classified still as a developing country, is famous in fully accomplishing divesting and privatizing the gas industry into eight (8) distribution companies (and two transmission companies) successfully in 1991. The original national body, "Gas del Estado" had actively promoted the development of natural gas industry by underwriting financing and employing subsidized prices to establish the national gas grids to a matured state, where now the government limits its role to regulatory activities only. Chile is an exception. Private sector enterprises are promoting gas industry without any regulations and with pure market principles targeting selected high-income customer clusters.

Pipeline businesses are capital intensive and require advance investment since financial recovery from the businesses comes comparatively slowly after connecting with customers one by one. Even if private sector operated, they are of highly public missionary nature. Especially in Europe, various public helps have been used for obtaining right of ways and for pipeline construction. Some of helps are direct subsidies and others are favorable loans from public developing banks. In some countries local governments give direct subsidies for laying distribution pipelines[3]. Governments have also directly intervened in international gas price negotiations in some European countries. In the U.S., there is no subsidy at all for interstates pipelines, but in the distribution level, which is regulated by each State, some cities permit tax-free bonds

[3] International Energy Agency, *Natural Gas Transportation, Organization and Regulation*, 1994

for promoting gas distribution network.

In Japan, there is no subsidies for the pipeline infrastructures at all, while the government helps gas distribution industry in the area of: research and development on environment and safety improvement regarding gas appliances development, installation of gas absorption and cogeneration facilities, favorable rate system for users of such systems, natural gas conversion by small utilities, natural gas conversion in industries, etc. A recent news, early September 2001, shows that the government plans to give a direct assistance for one third (1/3) of the cost of gas conversion in energy efficient industrial boilers for global environment and 10% for LNG conversion of coal power plants in 2002. The preferential gas rate for high efficiency gas cogeneration systems, for example, is about 30% lower than a regular gas price.

(NGV Promotion in Japan:)

Especially for NGVs, although Japan is not on the cutting edge in this field in the world with only 9,782 vehicles having been converted in the last decade (as of October 2001; increasing at a rate of 300 vehicles/month) with all-out gas industry effort, the government implements extensive fiscal NGV promotional supports. The policy is based on a Cabinet decree called the "Guideline for Global Warming Countermeasures Promotion". Both central government agencies and local governments are implementing the NGV promotion through various programs. Major programs are implemented through the Ministry of Economics, Trade and Industry (METI), while some others are also by Ministry of Land and Transportation, Ministry of Environment and the Ministry of Welfare and Labor.

For natural gas refilling stations (145 stations existing in October 2001), first, fiscal incentive funds from METI are offered through the "New Energy and Industrial Technology Development Organization (NEDO)" and the Japan Gas Association (JGA) to the facilities qualified with certain requirements and audit. Besides JGA's direct support, some JGA funds are also channeled through the "Eco-Station Promotion Association" to filling stations. The amount of a fund per a station, for example, is up to JPY90 million (approx. US$750 thousand) for installation, JPY 2 million (approx. US$16 thousand) for annual operation for three years and JPY 17 million (approx. US$140 thousand) for a station modification. In addition a tax incentive of either a 7% tax credit or 30% accelerated depreciation for the first year of installation can be applied.

For NGV conversion for a vehicle, promotional funds from the NEDO and the JGA are extended to NGV owners directly or through either the National Truck Association, leasing companies or local governments (prefectures or cities). The support by the funds normally amounts to 50% of the conversion cost. In addition the vehicle acquisition tax can be decreased by 2.7% (e.g., 3.0% of the price to 0.3%), and the annual vehicle tax (around 50,000 yen for regular cars) by 50% (for initial two years). If the NGV owner is a corporation, either a 7% tax credit or 30% special accelerated depreciation is awarded.

Local governments, i.e., prefectures and municipalities, award additional incentives for NGV promotion. While measures differ from government to government, most governments target buses, garbage collectors and courier trucks in the hope of restricting diesel oil vehicles. Some governments extend the incentives to individual owners. Tokyo and Osaka Prefectures intend to prohibit bringing in supplies by using diesel vehicles. Budgetary limitation normally restricts the number of annual NGV conversions receiving fiscal incentives from several to several dozens of vehicles. Most local governments support 50% of the net of the national government's support for a conversion.

The gas industry also sets special gas tariffs for NGVs to maintain competitiveness against gasoline and diesel. Such a price is in the range of 60-70 JPY/Nm3 (11.5-13.5 US$/MMBtu), approximately half-strong of residential gas prices, and the price ratio is at 0.6 to 0.74 against gasoline or 0.9 to 1.1 against diesel on the thermal basis.

(Gas Network Development Stages:)

As such, the government intervention in the gas industry promotion is not of only developing countries for early stages. However, especially looking at the gas industries in developing countries, the relationship of the growth of gas industry and the level of government intervention could be well explained by growth stages illustrated in Fig. 3-2-2. It is a common reality in this world that a public gas infrastructure cannot so easily take-off in the embryonic stage without a strong and serious governmental initiative for building up the business environment. Besides government, of course, existence of strong and serious private sector sponsors is also important.

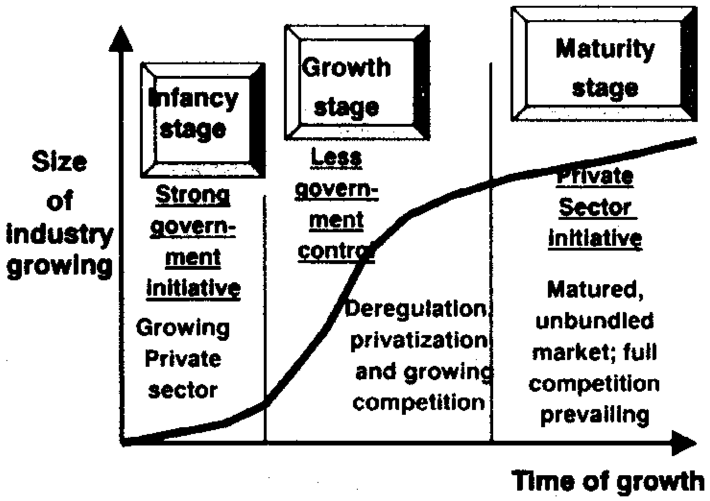


Figure 3-2-2 Gas Industry Development and Government Involvement

Since natural gas promotion in the Philippines is still a green field project, and the gas downstream is public infrastructure, government roles are important and necessary for gas promotion. Financing assistance and technology transfer will be the key to promotion. A governmental entity can be an investor, too. Otherwise, the government will be generally intervening in the market especially when (1) any monopolistic or exclusive nature exists and economic efficiency has to be pursued without competition, (2) national policy requires to allocate energy resources either in supply or demand for the security purpose, (3) remediation is required for market imperfection, and (4) when any gas related activity affects the public benefit or requires adjustment of public interests.

On the other hand, privatization and market principles are prevalent in the Philippines. Judging from the situation surrounding electric power industry reform as well as the country's financial situations, the Philippines will surely need to use private sector force to promote gas infrastructure and market. The national policy endorses roles of foreign investors although constitutional preference of domestic business dominance requires 60 % share holding and 100% management by its nationals in a public utility business. It draws attention that the new Power Industry Reform Act expressly defines that a power generator is not a public utility. We have a similar concern in LNG terminal, which will be hopefully better treated as a non-public utility business to introduce sufficient foreign expertise for smooth financing and perfect safety.

In summary, there will have to be a rigorous government initiative in creating the national gas industry to encourage privates sector companies for an embryonic period, since the promotion of gas distribution networks is of public nature to a degree requiring government support. If government cannot be an investor, harmonizing market roles and initiative roles will be a prerequisite in considering the promotion policies.

(3) Pipeline Gas and LNG

The future Philippine gas industry will consider natural gas both from pipelines and LNG, whichever depending on time to suit the growing demand, convenience of supply availability, international negotiations, cost and price. Thus the determinant is not necessarily the cost of plants and shipping only. International traders will look at which price will be accepted in the Philippine market, unless supply is real tight. International negotiations will not be well proceeded with without government support.

Either pipeline gas or LNG requires distribution pipelines to the customers in the country for the gas to be used. In-country rules for investors for pipeline infrastructure and operations have to be quickly installed. Also tariff systems are important to be known beforehand, as they are the source of cash flow projections.

(4) Gas Downstream and Market

Building the gas distribution network faces similar issues as in the gas transmission – i.e., right of ways, permitting procedures and tariffs, although downstream has still other different nature from transmission. Procedures and rules for building up the gas downstream businesses have to be quickly established.

How high the gas network cost is when measured in thermal value have to be well recognized and various incentives have to be installed until we see a normal gas market. Investors have to be able to come in more easily and there should be ways to win the inter-fuel competition. We hereby propose the government to use a portion of the "government take", or royalty, in the gas upstream operations to be used for creating the gas industry in the country, since this should be a consistent policy considering that the revenue from the "government take" is secured only by the upstream gas smoothly flowing to the downstream market where gas is accepted by consumers. National and corporate communications will have to be augmented for gas promotion as well as helping technology transfer and energy and gas education.

(5) Financing

The most important key to the goal will be financing. Private sector financing for a project serving general customers like gas distribution, industrial or residential, normally faces difficulties, requiring government roles. Government roles are normally both investment and regulatory activities in developing countries. The Philippines is determined to invite private sector investors in infrastructure development, but considering the difficulty of financing, the author would recommend that the government hold part investor roles if there is difficulty in finding full private investor investors in gas infrastructure development. Nevertheless, we will describe how private sector gas companies financed their networks through connection fees in other countries so far.

Traditional private sector gas companies have financed the distribution networks through both own direct investment and connection fees from new customers as well as bond issuance and bank loans. Such companies typically invest in strategic main transmission or distribution lines and facilities with own money and charge new customers connection fees for financing other marginal pipelines linked to those customers. This relationship is demonstrated in Figure 3-2-3.

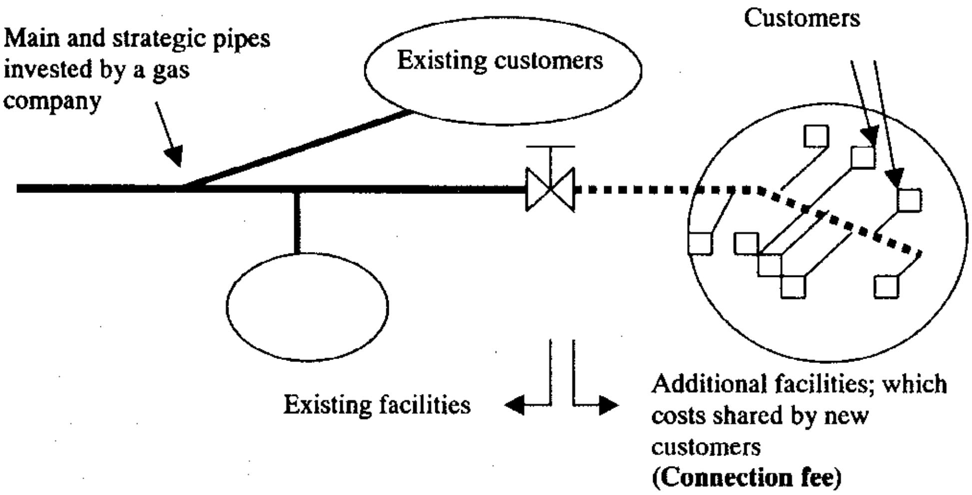


Figure 3-2-3 Connection Fee: Financing by Customers

When certain facilities are financed and contributed to the gas utility by customers, repayment is not directly made but the part of capacity charge in the gas rate is discounted according to the size of the customer (size of the gas meter). The part of facilities paid by customers belongs to the gas company but comparable investment cost saved must be deducted from the rate base. In this way, gas used to be used by customers of certain higher income brackets. The share of customer financing through connection fees spans from 5 percent to 100 percent of the investment value, depending on the region or company, while 100% is normally the case. In Japan such cost is approximately US$2,000 to 3,000 per customer.

Now how this is applicable to the Philippines is a question especially in the embryonic stage. Customers will have to pay for the in-house pipes and a gas meter, which belong to the customers, in addition to the connection fee. When a new building or a house with gas pipes is constructed, the price of the building or house includes such costs, say US$ 500 to 1,000 in Japan, without buyer's notice. A gas company will aggressively approach house builders for gas promotion. The costs, however, will be a considerable burden to existing residents who want to newly use gas. The government will be able to help them in giving credit or loans if gas promotion is intended for. A nationally owned gas company will be able to minimize the share of the connection fee of the total investment by using international financial institutions.

The JICA study, for simplicity, will assume that all the network costs will be financed by the gas company through arranging some international financing for financial and economic analysis purposes assuming possible government involvement. The in-house pipes and gas meters will be paid by customers with certain tax credit helps. In actuality, however, the gas company, and the regulatory agency, will have to consider whether to charge the connection fee or not, or how much, before implementation.

3-2-2 Recommended Measures for Gas Promotion

(1) Promotion Principles and Assumptions

Fostering of natural gas industry has to involve two fields; the development of the pipeline infrastructure and the gas market promotion. The thrust of the former will be primer incentives for the investment promotion and that of the latter will be market competitiveness augmentation policies. The policies for gas industry promotion will be considered in a few categories:

- ☐ Economic and financial measures – tax and subsidy, prices, privatization, competition, incentives to investors,
- ☐ Legal and regulatory framework – price and tariff control, eminent domain, etc.
- ☐ Procedural and technical standards - transparent and predictable procedures
- ☐ Social and political systems – including education and training, dissemination of information on the benefit of gas, inter-departmental communication, economic safety net for poor or weak industrial customers (welfare policies), etc.

Principles specific to the Philippines to be considered will be: (i) to avoid distorting the market principles as much as possible, (ii) not to be detrimental to the existing government revenue system, (iii) to naturally abide with existing legal systems and jurisprudence as well as policies as much as possible. Further we will take in (iv) the principles implied by the new Power Industry Reform Act (RA9136) such as common access, abolishing subsidies, privatization and competition promotion as much as possible. We will reiterate at the same time, however, that the difference between gas and electricity is so large as, e.g., one is so infant and the other is comparatively matured in the Philippines.

The Philippines gas downstream industry is assumed in this JICA Study to comprise gas transmission (pipeline) companies, LNG terminal companies and gas distribution companies. Actually there will be more industries such as gas equipment sales and service companies, gas appliance manufacturers or importers, plumbers, pipeline construction companies, etc., which will be neglected in our study. We assume that the LNG terminal company will be treated as a non-public utility company in consideration of financing, technological and operational conveniences. Unbundling of the transmission and distribution will be a separate matter, while we assume separate accounting in the financial analysis.

(2) Economic and Financial Regime for Gas Promotion

a) Establishing Preferred Gas Status to Allow Incentive Policies Accepted

Entitlement to tax incentive benefits requires that the relevant enterprises be listed with the Investment Priority Plan (IPP) under the Omnibus Investment Code of the Philippines. The Code is regulated by the Board of Investment (BOI) and the

Department of Industry and Trade (DTI) and revision by inclusion and deletion is made annually in consultation with the private sector. Normally entitled are preferred industries, which are pioneer area or export industries.

Fiscal incentives are permitted to those preferred industries in the form of income tax holiday (ITH), tax credits, tax and duty free importation, simplification of customs procedures, etc., depending on items. Similar incentives are awarded to the industries in special economic zones (i.e., PEZA, SBMA and CDC) under the Export Development Act (EDA).

Gas pipeline network development involving private sector from an embryonic stage in a tropical developing country is truly a new and pioneering project. This is public infrastructure business involving new technologies directly for the benefit of the people as well as industry. Although detailed conditions may involve extra discussions between DOE and other government agencies, it will have to be well understood that this industry should be regarded as a pioneer one which will be beneficial to the nation.

For the promotion policy side, the procedure for attaining incentive policies will be to:

1) Create a policy status of gas as a preferred energy due to: merits on urban air cleanliness, friendliness to the globe (less carbon dioxide), inherent higher efficiency, urban convenience, superior urban piped energy transportation (e.g., superior to truck energy transportation through the streets), cutting power generation peaking and decreasing stratospheric ozone depleting gases by promoting gas air-conditioning, etc.

2) Consider incentives while avoiding detriment to market principles and existing government financial balance as much as possible. Consider basic principles shown in the Power Industry Reform Act such as common access, abolishing of direct and cross subsidies, private sector business promotion, competition promotion, etc., as much as possible while noticing the difference between gas and electricity at the same time.

3) Award incentive to gas facility investment based on the preferred status stated above for certain initial period. Award investment tax saving while avoiding direct appropriations by the government through, e.g., taxable income deduction, direct

tax credit to deduct from tax amount, or special depreciation.

Fiscal assistance on an investment stage like these is regarded as less detrimental to market principles than direct subsidies on price preference, which might distort economic prices. There are actual examples of tax credit in other countries such as: the energy saving investment tax credit which was applied to individuals and corporations in the US in 1980s, and gas air conditioning and gas cogeneration tax credit which is currently available in Japan and US, due to preference of replacing oil.

b) Fiscal Incentive Measures Based on the Priority Plan

Based on the pioneer status and inclusion in the Investment Priority Plan (IPP) of the gas network development, and considering comparatively weak financial viability of the gas public infrastructure business, we would propose the following incentive measures to be taken:

1) Apply tax holiday policy to the gas network facilities as is used in locating factories in new industrial estates including, e.g., zero corporate income tax for initial 10 years for specifically defined pipeline projects.

2) Excise tax for gas may be zero from scratch. Consider abolishing LNG import tax from 2006, after confirming successful installation of Camago/Malampaya gas, for example. Reduce import duties for materials for gas network from 2005, for example.

3) In general difficulty of project financing scheme for tariff revenue dependent projects like distribution without firm gas purchase agreement, customers can fund in the distribution projects in the form of initial connection fee payment outside gas tariff. This is common in gas distribution business. Customers also have to invest in interior pipes, or the pipe installation within their premises, which could be directly subsidized in the form of tax credit. The government can give caps on the credit amounts, say 30% of the publicly certified costs.

c) Fiscal Incentive Measures – with Special Gas Fund Proposed

Beside fiscal incentives based on the pioneer status described in the above section, we further propose to create a special gas fund or account from a part of the purse of upstream royalty for direct incentives. We note that the price of gas from the Camago/Malampaya fields at Tabangao is comparatively high and this involves the government take or royalty in the upstream, which may be best used partly for gas downstream development. If the gas is exported, such royalty will be well distributed to the nation through general government budget.

In the Philippine case, however, the gas will be exclusively consumed and paid by domestic consumers who should be first qualified to the benefit of gas as well as other energy users and non-users. This can be accomplished through establishing gas pipeline networks, which deserve such fund as a primer for development. This is because the royalty is actually created only by the gas reaching the final customers who will be paying for gas or electricity. The royalty will be giving birth to a fresh cash flow to the government after starting up of the Camago/Malampaya project in 2002, and the use of a portion of that fund for incentives for the downstream development could not be detrimental to the existing government budget balance.

The size of the "Special Gas Fund Account", we propose, will be limited to only a portion of the total government take and to a limited period, and the use of it will be limited to the primer of gas infrastructure investment and to raising the competitiveness of gas in the inter-fuel competition. If gas is not competitive enough due to the royalty, this assumption needing examination, the price adjustment by applying the fund from such account will not be distorting the competition.

The fund may be used as the purse for following strategic incentives:

1) Natural gas vehicle projects may require public help due to the public environmental merit and due to high estimated costs. Public subsidy for this kind of project is common in many countries. The part of public infrastructure, i.e. gas filling stations, may receive investment tax credit on, say, 30% to 50% of the certified investment amount. Public bus entities, as well as others having fleet vehicles, could invest and own model gas filling stations, with the help of the fund, possibly jointly with help of international financial institutions. Financial help for NGV conversion kit installation will be hopefully a great primer.

2) Gas cogeneration and gas air-conditioning may have recognized merits due to high energy efficiency to receive investment tax credit on, say, 30 to 50% of certified

investment amount. If we need a comparable foreign example, about 7% of tax credit assistance and 30% gas price discount are common in Japan.

3) Gas conversion from oil (fuel oil or diesel) may receive investment tax credit on, say, 20 to 40% of the certified amount of investment in gas conversion facilities.

4) Gas price discount for strategic use of gas, i.e., NGV, gas co-generation and gas air-conditioning, may be justified as a kind of refund from the government take for the sake of energy efficiency and urban and global environment. Considering the difficulty of financial for NGV, we propose 50% discount on the price of gas for NGVs and 30% discount for cogeneration and gas air-conditioning. The latter is actually common in Japan.

5) Further, the fund may be used for a direct assistance to the investment in distribution pipelines which otherwise would be partly financed by incoming customers through connection fees.

We have made a preliminary computation on a possible incentive program to see the sensitivity of the program on the total amount of fiscal assistance versus the government take amount. The proposed program and assumptions are in Table 3-2-1, and Table 3-2-2 respectively, and results are in Table 3-2-3. The item 5) above, however, is not included. More detailed computation is shown in Annex 3-5 attached to the end of this chapter.

The results of the computation show that spending of several percent of the net government take will cover those incentive amounts for the embryonic stage of the gas industry development. To give the gas real competitiveness against other fuels, however, direct assistance to the pipelines may be necessary considering high gas price at Tabangao.

Assumptions for this estimate are kept very conservative. The estimation has been shown only for an indicative purpose to know the size of required fiscal support. The effect of the support for NGVs as well as other special market and the required size of fiscal support are analyzed with detail in Chapter 4, as readers are encouraged to look into. We have tried to focus the fiscal support on facility investment and avoid gas price discount in the computations, but eventually found that some price support is inevitable for viable NGV operation.

The gas industry in the Philippines could be much more aggressive. Number of NGVs and filling station installations, for example, could be expanded without intimidating the proposed Special Gas Account budget. Assistance to gas cogenerations cane be increased, too. Further assistance may be given to pipelines, while not shown here, to accelerate the network development.

Table 3-2-1 Proposed Incentive Program

Proposed Incentive Program (with estimated size in around 2010)

Incentive Credit Programs	Kind of Assistance	Level of Assistance (example)	Approximate annual size for approvals	Preliminary Investment Amount ($1000)	Credit Amount ($1000)
NGV Incentive Programs	Tax credit to qualified private filling station	50% assistance	5 stations	2,685	1,342
	Assistance to public filling stations	100%	2 stations	1,008	1,008
	Assistance to conversion kits	100%	300 vehicles	645	645
	Special gas price discount (High case)	20% discount	0.98 mmcfd	2,776	555
	Subtotal			7,114	3,550
Cogeneration Investment Tax Credit Program	Tax credit to qualified private sector Co-generation	20% assistance to investment	5 units	5,370	1,074
	Assistance to public and welfare entities (hospitals, schools, etc.)	30% assistance	5 units	4,296	1,289
	Subtotal			9,666	2,363
Gas Air-Conditioning Tax Credit Incentive Program	Tax credit to qualified private sector Co-generation	20% assistance to investment	10 units	21.5	43
	Assistance to public & welfare facilities (hospital, schools, etc.)	30% assistance	5 units	1,611	483
	Subtotal			1,633	526
Credit to Investment for	Industrial users	20% assistance	50 customers	268	54
Gas Conversion from	Commercial users	30%	70 customers	150	45
Other Fuels (Assistance to in-house pipes and conversion work)	Residential users	30%	1700 customers	3,651	1,461
	Subtotal			4,069	1,560
Incentive Grand Total ($1000)					7,999
Estimated net government take from C/M gas ($000)					276,410
Rate of incentive payment to the government take total (%)					2.89

Table 3-2-2 Assumptions for Expenditure Estimates

Assumptions Summary – Preliminary

		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
NGV												
No. of filling stations	Private	0	0	1	1	3	3	3	4	5	5	5
	Public	0	1	0	1	3	3	3	2	2	2	2
	Total cumulative	0	1	2	4	10	16	22	28	35	42	49
NGV Conversions		0	2	4	6	20	50	100	200	300	400	500
	Cumulative NGVs	0	2	6	12	32	82	182	382	682	1,082	1,582
Gas sales to NGVs	(mmscfd)	0	0.02	0.04	0.11	0.42	0.53	0.63	0.74	0.98	1.11	1.23
Expenditure Total	$ '000	0	525	586	1,286	4,188	4,579	5,021	5,602	7,114	7,827	8,570
Gas Cogen.												
No. of Installations	Commercial	-	-	-	-	5	5	5	5	5	5	5
	Public & welfare	-	-	-	-	5	5	5	5	5	5	5
	Cumulative installations	-	-	-	0	10	20	30	40	50	60	70
Expenditure Total	$ '000	-	-	-	-	9,000	9,162	9,327	9,495	9,666	9,840	10,017
Gas Air-conditioners												
No. of Installations	Commercial	-	-	-	-	10	10	10	10	10	10	10
	Public & welfare	-	-	-	-	5	5	5	5	5	5	5
	Cumulative installations	-	-	-	0	15	30	45	60	75	90	105
Expenditure Total	$ '000	-	-	-	-	1,700	1,731	1,762	1,793	1,826	1,859	1,892
Natural Gas Conversion												
No. of conversions	Industrial	-	-	-	-	50	50	50	50	50	50	50
	Commercial	-	-	-	-	70	70	70	70	70	70	70
	Residential	-	-	-	-	100	500	900	1,300	1,700	2,100	2,500
	Cumulative customers	-	-	-	0	220	840	1,860	3,280	5,100	7,320	9,940
Expenditure Total	$ '000	-	-	-	-	590	1,415	2,270	3,154	4,070	5,018	5,999
Grand Total Expenditure	$ '000	0	525	586	1,286	15,478	16,887	18,379	20,044	22,676	24,543	26,478

Table 3-2-3 Incentive Program – Result of Estimate

Size of Fiscal Support (Lower Price Case)

		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Fiscal Support Estimates:												
NGV	$ million	0.0	0.5	0.3	0.8	2.5	2.7	2.8	2.9	3.6	3.9	4.2
Gas Cogen.	$ million	0.0	0.0	0.0	0.0	2.2	2.2	2.3	2.3	2.4	2.4	2.4
Gas Air–conditioners	$ million	0.0	0.0	0.0	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Natural Gas Conversion	$ million	0.0	0.0	0.0	0.0	0.2	0.5	0.8	1.2	1.6	1.9	2.3
Grand Total	$ million	0.0	0.5	0.3	0.8	5.4	5.9	6.5	6.9	8.0	8.8	9.6
Size of Government Take on C/M*:												
National Governemnt	$ million	71.9	89.8	88.3	86.5	85.0	171.9	174.8	174.6	156.9	154.2	146.9
Income Tax	$ million	54.8	58.4	67.3	65.9	64.8	130.9	133.2	133.0	119.5	117.5	111.9
Total	$ million	126.7	148.2	155.6	152.4	149.8	302.8	308.0	307.6	276.4	271.7	258.8
Support vs. Gov. Take												
Ratio:	%	0.0	0.3	0.2	0.5	3.6	1.9	2.1	2.3	2.9	3.2	3.7

Note) *Source of Government take: DOE; excluding local governemtn take

d) Securing Public Financial Institutions for Gas Use Projects Having Environmental Benefit

1) The government can be active in forming various gas use projects having environmental merit for seeking international financial help. This requires certain effort in launching tangible projects to benefit the public and international community.

2) The government could give public guarantee for semi-public infrastructure

projects after examining high success ratios without own financial difficulty but with certain effort.

e) Funding for Research Projects to Promote Use of Gas

1) Assistance for technical advancement – may be applied to small and specially and transparently organized associations, cooperatives or universities for promotional projects for natural gas -

> This kind of direct financial assistance for "study" natured projects is common in many industrial countries, i.e., US, Europe and Japan. Many new gas use technology research developments are directly subsidized as to enhance relevant research and education for eventual gas promotion. Currently in Japan, for example, natural gas conversion projects in small and less creditworthy gas utilities are partly subsidized through specially organized association in pursuit of national benefit of replacing oil.

2) Loan guarantee for the same purposes as above to be applied to technology or energy related business inception projects. Loan guarantee was common for new energy technology development through the National Synfuel Corporation of the US in 70s to early 80s. This does not incur any direct expense to the government if applied to well planned projects promising success.

(3) Legal and Regulatory Measures

a) Making Gas Regulatory System Simpler

While most regulatory elements are already addressed in the existing legislation, they are widely fragmented over various statutes. The mandate of gas use promotion will ultimately need to make this complexity to be reformed into simple legal statements easily understandable to the investors and financiers. The largest policy measures will be a countermeasure to the fragmentation of the regulatory elements.

Integrated Law: A final goal for a simpler system is to install an integrated natural gas law and the Philippines will eventually need it. The law, after taking in all the necessary regulatory elements, will clearly repeal all the duplicative provisions in the past statutes, so that investors, financiers, operators and customers have only to read the very law and directly relevant regulations for major items. Since creating an act in the legislature may require too big an effort as in any country, we hope and assume that this will be done, e.g., in ten years.

One Stop System Guideline: The next best measures will be to integrate all the existing statutes or important provisions into one guideline document so that investors, financiers, sponsors and customers can come to the DOE and instantly know what the rules are, which agency handles them, and what to do to do the business under the current legislative and regulatory systems. This will not be difficult since major items are already picked up in this Study or ABD Project report. We will assume that this kind of measures will be established in five years.

Such an integrated document will normally specify the provisions, e.g.,

- Basic policy
- Gas business inception procedures
- Accounting and inspecting system
- Facility installation approval procedures
- Gas technical standard
- Right of way
- Tariff and transmission fees

Others include tax and subsidy, privatization, competition, incentives to investors, etc.

Flexible Franchise Management: Gas network infrastructure is more expensive in the countries in warmer climate regions in view of amount of gas used especially for smaller customers. If mandate is given to supply gas to all the captive people in the franchised area, economics is often negative, unlike northern developed countries where high gas consumption per customer is promised. Choice of only preferred productive customers for gas distribution may be permitted to produce viable business. Preferred customers are normally large customers located in rather high density.

b) Implementing Rules and Regulations

Early establishment of implementing rules and regulations for pipelines, distribution, technical and procedural standards is recommended. The ADB project of 2000 will be the base for this.

c) Tariff Considerations for Gas Promotion

Early suggestion of the outline of the tariff systems is recommended for the public or private sector inventors for making financial projections. Private sector projects can be operated in a sustainable manner only by securing revenues to recover the costs in investment, maintenance and operation. The tariff system, normally regulated, has to guarantee such revenue on various principles.

Economy of scale principle has to be considered for larger customers since the cost per thermal value is truly lower for those customers compared to smaller customers, while political pressures often make the prices to general public lower than a level of costs in other countries, nullifying the project. Such principle is automatically realized by adopting two-part (or three-part) tariff system where a gas rate consists of fixed monthly payment to reflect the fixed cost (i.e., capacity charge) plus energy charge based on the amount of gas used. A rate system where more gas use means cheaper rate per Btu will hopefully promote use of gas.

When a new project is launched without past cost and revenue data, often considered is LRMC (long range marginal cost) based tariff making. The cost is calculated based on the 10-20 year cash flow analyses to reflect it in the tariff system, with periodical review and revision. Since investment recovery is to be made in a longer term, the tariff based on this system is usually lower than in other systems, more beneficial and competitive as well, may require more short-term cash management operations.

Another system is the value based tariff system, where tariff is determined by the market conditions like international oil prices, economic indices, and gas prices in the upstream, etc. The tariff for extra large customers are often based on this system. While lacking transparency, this often reflects a real market value. Gas tariff for special purposes, including gas for power generation, may be left outside the normal rate regulation requiring certain transparency and general approval. By this change of the systems into variably reflecting market values, tariff principles are transiting from the traditional "just and reasonable" tariff to "fair, equitable, and flexible" tariff systems.

Variations in the tariff system due to specific conditions should be permitted. One is the interruptible tariff system, which give discount to the customers accepting interruptible supply, or otherwise semi-flat load customer tariff, which gives discounts due to high load use of pipelines. Although such customers have certain back-up facilities, gas price discounts due to just and various reasons will promote gas use.

A system of connection fee or any other initial fees to cover initial costs as customer's financing will lower the afterward monthly payment and gas charges, possibly promoting use of gas.

(4) DOE Organization for Gas Use Promotion and Training

For implementing all the gas downstream promotional measures stated above as well as a few more important measures to be described below, the DOE will need a group of personnel for gas industry administration with certain expertise and experiences. Looking at the current DOE organization shown in Annex 3-2, such a group may be well created under the Energy Industry Administration Bureau, or either an ad-hoc group with Undersecretary Office for a transition period, although other bureaus will be closely linked to it in many specialized relevant areas.

Based on the reviews on the current regulatory systems stated earlier in this chapter, there is still uncertainty on which agency will regulate gas prices after the Electricity Industry Reform Act (RA 9136), Sec.43, has defined that the functions of the ERC are limited to items in the electric industry, and the former ERB is expressly abolished by Sec.38. Attaching the gas ratemaking power to the ERC will require a Congress action. Otherwise, without any agency having legal jurisdiction over gas prices, the DOE now may be able to play to guide gas prices to economically appropriate directions, such as ways of deregulated oil prices. The DOE may consider gas prices anyway as an important key in gas use promotion, even without price regulatory powers.

The group of several personnel in the DOE to be newly created will be taking initiatives forming and fostering gas industry by accommodating rules and policies, for gas infrastructure, gas supply conditions to the market, administering gas market enterprises and promoting financing, etc.

Many people in many departments of the DOE already have deep knowledge and expertise on natural gas resources along with the long time development in the upstream. Only additional knowledge is required in the gas downstream development area, particularly for building up regulatory systems. The people in the expected group as well as others in relevant bureaus will need to acquire expertise and knowledge on existing practice in the existing gas industries in other countries as well as in those governments, by dispatching them to those countries or by inviting instructors from. One of the first tasks of the DOE for the promotion may be to plan such training and education of a few dozen officials including some committed officials of the private sector by talking to other governments.

For reference, such government regulatory functions in Japan, price or non-price, is held by the Gas Market Division under the Electricity and Gas Industry Department, the Agency of Natural Resources and Energy, Ministry of Economy, Trade and Industry (METI). The Division administers vast amount of gas related statutes, and currently faces, through advisory committees, heavy debates of restructuring of the both industries. As an other example, Korean gas industry, public and private, sent hundreds of trainees to Japanese gas industry, accepting Japanese language materials, when they quickly built up their gas downstream industry in late 1980s, while current Japanese gas industry may not have such size of ability to receive trainees speaking English language.

(5) Other Promotional Policy Measures

a) Technology Transfer

The Philippines seems to need to acquire certain technical experience to promote gas industry and the government can help for the relevant international public arrangement. The Master Plan may be based on the assumption that the Philippine has ready expertise on use of gas. In fact, while gas distribution may not require competitive edge technologies, there are hardly cases of successful installation of this business without technical transfer from existing gas industries. Learning experiences is still important for efficient operations when the industry already exists elsewhere.

b) Public and Official Communications and Education

The gas use promotion requires public acceptance in many ways. Also the customers may not want to use gas without full knowledge of gas. Officials in various agencies may not work efficiently for necessary steps to gas promotion without full understanding of the nature and policies of gas. The media and certain group of the people may move against gas without the same correct knowledge. The public may be put on danger without the knowledge of safety and non-safety aspect of gas.

The government can fund publishing various texts and materials for the public, industries and officials of the Congress and relevant agencies on the truth of natural gas. Seminars may be forwarded to investors. Schools can include science on natural gas in their texts.

Vocational schools can include more technical matters on gas.

c) Combined Efforts

Gas network infrastructure is normally expensive and thus only efficient work plus combination of several promotional policies will promote consolidated use of gas. Even when a normal cash flow analysis shows negative in gas distribution business, strict selection of favorable conditions with combined promotional policies may make the project viable. Examples of various policies are:

1) Policy statement for gas promotion – to encourage the development
2) Finance back up by government– Comfort letters to financiers
3) Financing R&D – Research and development activities for efficiency improvement by using gas
4) Support universities – infrastructure development, cogeneration, GTL, supply, energy use systems, etc.
5) Application technologies – roles of non-academic institutions, industry, government
6) Public education – Promote recognition for energy and gas; Natural gas infrastructure – cooperation needed from residents for national security
7) Local government education
8) Vocational Training
9) Trade associations – setup gas association for mutual and nationwide cooperation for gas promotion.

3-2-3 Linkage to Scenarios in the Master Plan

How the business environment for natural gas will be made up seriously affects the Master Plan for gas promotion. We hereby address two (2) scenarios for the Plan: i.e.: (i) a Scenario without New Policies and (ii) Extra Quantitative Promotional Scenario.

The quantitative promotional scenario will extract the promotional polices stated above and include the following policies:

1) Apply tax holiday for initial 10 years for designated pipeline projects.
2) Excise tax: zero from scratch. Abolishing LNG import tax from 2006. Reduce import duties for materials for gas network from 2005.
3) Allow initial connection fee payment to be charged. Pipe installation within customers' premises receive tax credit for the 30% of the investment.
4) For natural gas vehicle projects, 20% of the certified investment amount will be tax-credited.
5) Gas cogeneration and gas air-conditioning receive investment tax credit on 10% of certified investment amount.
6) Gas conversion from oil (fuel oil or diesel) may receive investment tax credit on 20% of the certified amount of investment in gas conversion facilities.

The Action Plan presented elsewhere in this Study will include some of the items described above with appropriate yearly implementing plans.

Gas will be first used for power generation in a case of new supply source development if the demand for gas power is available, and then for industrial purposes and smaller customer markets including natural gas vehicles. Not only the gas distribution costs but also difficulties for establishing the network are in an order of smaller customer (residential and commercial), industrial and power generation.

Recognition of natural gas toward occupying a greater share in the Philippine energy picture is growing on the other hand, in which case the gas will go to the industrial and smaller customer markets with benefit to the nation, requiring extra policies and implementation.

Annex 3-1

List of Existing Statutes and Policies Relevant to Natural Gas

(1) Legislative and Presidential Level Statutes

(i) Commonwealth Act No.146 (CA146) of 1936 or the "Public Service Act": Defines "Public Service" and the "Certificate of Public Convenience (and Necessity)" and devolves the power to issue such certificates and approve franchise to the then Public Service Commission, the general jurisdiction of which has been inherited to the current ERB for price regulatory issues and to the current DOE for non-price regulatory items. The provisions in the Act not affected by statutes promulgated later are still in full force as are often cited.

(ii) Petroleum Act of 1949 (Republic Act 387, June 18, 1949) as amended: Declares any petroleum operation as a public utility and regulates concessions of pipelines for petroleum including gas, as well as exploration, development, production and refining. Authorizes Secretary of Agriculture and Natural Resources to create the office to administer these regulations, now having been devolved to the DOE. The pipeline concession rules mandate the concessionaire to offer the marginal pipe capacity to common carriage.

(iii) Republic Act No. 6173 (RA 6173 Oil Industry Commission Act, April 30, 1971): is to create the Oil Industry Commission, as an independent commission, to regulate and supervise the downstream oil industry including gas. The most part of this act is deemed repealed by the Downstream Oil Deregulation Act of 1998 except for gas, the jurisdiction over which is still debated.

(iv) Presidential Decree No. 87 (or PD 87, Dec. 31, 1972): is to allow the Government to directly participate in the exploration and development of indigenous petroleum including gas to accelerate discovery and production, details the contents of service contracts and create the Petroleum Board under the chairmanship of Secretary of Agriculture and Natural Resources. The Board includes as members Secretary of Finance, Secretary of Justice, Chairman of the Board of Investment, Governor of the Central Bank, Secretary of Trade and Tourism and Director of Mines who is the executive officer of the Board. The Board is attached to the National Economic Development Authority (NEDA) and handles petroleum service contracts. PD87 supercedes many Articles of Petroleum Act of 1949. The functions of the Board was later transferred to DOE.

(v) Presidential Decree No. 1206 (PD 1206 Creating the Department of Energy, October 6, 1977): created the former Department of Energy responding to the 1973 oil crisis for the objectives of achieving eventual energy self-reliance, rationalizing the energy development programs and in view of the necessity of no less than an agency with departmental status for energy management. The two Bureaus of Energy Development and Energy Utilization were created under the Department, as well as PNOC and NPC were attached to the Department. The (former) Board of Energy was also created by this Decree under the Office of the President replacing the Oil Industry Commission and the Board of Power and Water Works except for the functions relative to waterworks. The Board of Energy was to regulate and fix the prices of petroleum, piped gas, electric power of electric companies as well as executing other regulatory functions.

(vi) Presidential Decree No. 1700 (PD 1700, Granting the Board of Energy the Power to Regulate Pipeline Concessionaires, July 10, 1980): added to the Board of Energy the power to regulate and fix the rates of pipeline concessionaires (thus transmission tariff being to be regulated).

(vii) 1987 Constitution of the Republic of the Philippines defines that all the natural resources regress to state ownership and the responsibility of development of natural resources is put under the President (Section 2, Article XII). (The price of gas from Camago/Malampaya, for example, is given a floor by Department of Finance under the delegation of Presidential power (Executive Order 172 of 1987) regardless of the defined function of the ERB.) Further, Article XII, Section 11 directly stipulates the franchise of public utilities, leaving suspicion of the franchise to be subject to Congressional control. Manila Gas Corporation, for example, is given the franchise by a Congressional Decision (Republic Act 2278, January 26, 1959), as well as First Gas as stated later (xii).

(viii) Executive Order 172 of 1987: creates the independent Energy Regulatory Board (ERB) reconstituting the Board of Energy hereinto. Defines the institutional organization, jurisdiction, powers and functions of the Board, e.g., to fix and regulate the schedule or prices of piped gas as well as the rates of pipeline concessionaires. Also defines the hearing procedures before tariff setting, which is currently applied to electric tariff regulation.

(ix) Department of Energy Act of 1992 (Republic Act 7638, December 9, 1992): created the current Department of Energy (DOE) under the new Constitution to rationalize the organization and functions of government agencies related to energy. The DOE is to carry out the defined national energy policy and to prepare, integrate, coordinate, supervise, and control all plans, programs, projects, and activities of the Government relative to energy exploration, development, utilization, distribution and conservation.

(x) Downstream Oil Industry Deregulation Act of 1998 (Republic Act No. 8479, July 28, 1997): to define the processes to deregulate all the petroleum market including that of LPG, specify anti-trust provisions, set a uniformed import duty of 3%, defining the DOE and ERB functions in the process, define the activities in the transition phase, and finally define the jurisdiction of ERB to regulate the price of piped gas.

(xi) The Tax Reform Act of 1997 (RA No. 8424) and The National Internal Revenue Code of 1997specify taxes relevant to natural gas industry gas as follows: 1) Sec. 109 (e) of the Code exempts any form of natural gas from VAT in lieu of excise tax; 2) Sec. 119 "Tax on Franchises" levies 2% on the gross receipts by electric, gas and water utilities; 3) Sec. 148 "Excise Tax on Petroleum Products as amended" levies 3 % on major petroleum products except for LPG which is applied zero (0) % if not used for motive power; 4) Sec. 151 "Excise Tax on Mineral Products", in its sub-provisions (2) and (4), specifies that locally extracted gas and LNG shall be taxed at 2%. Further, 5) Sec. 108 defines the VAT on sale or exchange of services including domestic common carriage except those under Sec. 119. Thus natural gas internally taxed on franchise only.

(xii) Philippine Clean Air Act of 1999 (RA No. 8749, 1999) and proposed relevant Implementing Rules and Regulations: are to apply stringent regulations on air quality comparable to those in California.

(xiii) Presidential Decree No. 314 (PD314 of November 2000) "Modifying the Rates of Import Duties on Imported Crude Oil and Selected Refined Petroleum Products under Section 104 of the Tariff and Customs Code of 1978 (PD 1464 as amended" reduces the import duties of selected petroleum products to zero (0) % from three (3) % to be effective for three (3) months due to current hikes of international petroleum prices. The Decree has been extended as of February 2001. The duties had been reduced from 10% to 3% at the time of downstream oil deregulation.

(xiv) An Act Granting First Gas Holdings Corporation A Franchise in Luzon (Republic Act No. 8997, January 11, 2001), passed Congress on October 10, 2000; was approved by the President in January 2001. This fresh franchise legislation reminds us of a preceding series of similar Acts for Manila Gas Corporation: Philippines Legislative Act No. 2039 (1924) and RA No.2278 (1959).

(xv) Electric Power Industry Reform Act of 2001 (RA 9136, June 8, 2001), called the "Omnibus Power Bill" for long time, is now a law to define the future Philippine electric power industry in a very advanced way in the world. The law launches the "unbundling of the industry into four (4) sectors", "transmission pool", "open access", "power exchange", wholesale electricity market, and creation of the independent Energy Regulatory Commission (ERC) replacing the existing ERB. The notions of "franchise" and "public utility" are clearly redefined for the electric industry. The law allows relevant utilities to exercise the "power of eminent domain" subject to the requirements of the Constitution and other laws. The industry structure and functions by this law are demonstrated in a diagram in Appendix. Actual enactment of this law will depend on the relevant implementing rules and regulations, which are in the process of establishment by DOE for a target date within a year. This seems to potentially affect future gas industry.

(2) Existing Regulations Relevant to Gas

On the level of regulation, guideline and official opinion, important rules in the natural gas sector are as follows:

(i) "The Policy Guidelines on the overall development and utilization of natural gas in the Philippines" (DOE Circular No. 95-06-006, June 15, 1995) which guides the provisions to:

1) promote the role of natural gas into the energy supply mix,
2) let the Camago/Malampaya gas serve as the foundation of the Philippine gas industry,
3) encourage private sector participation in the gas industry,
4) regulate the gas industry to structure to facilitate safe operation, industrial growth and non-discriminatory access
5) comply with environmental regulations, and
6) promote the indigenous gas to stabilize the price

(ii) "Rules and Regulations Implementing Section 5 of DOE Act of 1992 or RA 7638" (Energy Regulation ER 1-94, May 24, 1994): setting direct benefit from energy resource developer and power generation proceeds to local governments, price being one (1) centavo /kWh (approx. 0.038 US cent/kWh)), to be used for electrification, development and livelihood fund, forestation and watershed management, and health/environment. Its amendment on July 31, 1996, extends the provision to power generator using gas including LNG.

(iii) Department Circular No. 2000-03-003 (March 17, 2000) partly amends the ER 1-94 and further gives great details to the allocation of the fund from power generators. Its application to natural gas and LNG fired power plants are included in its Section 4.

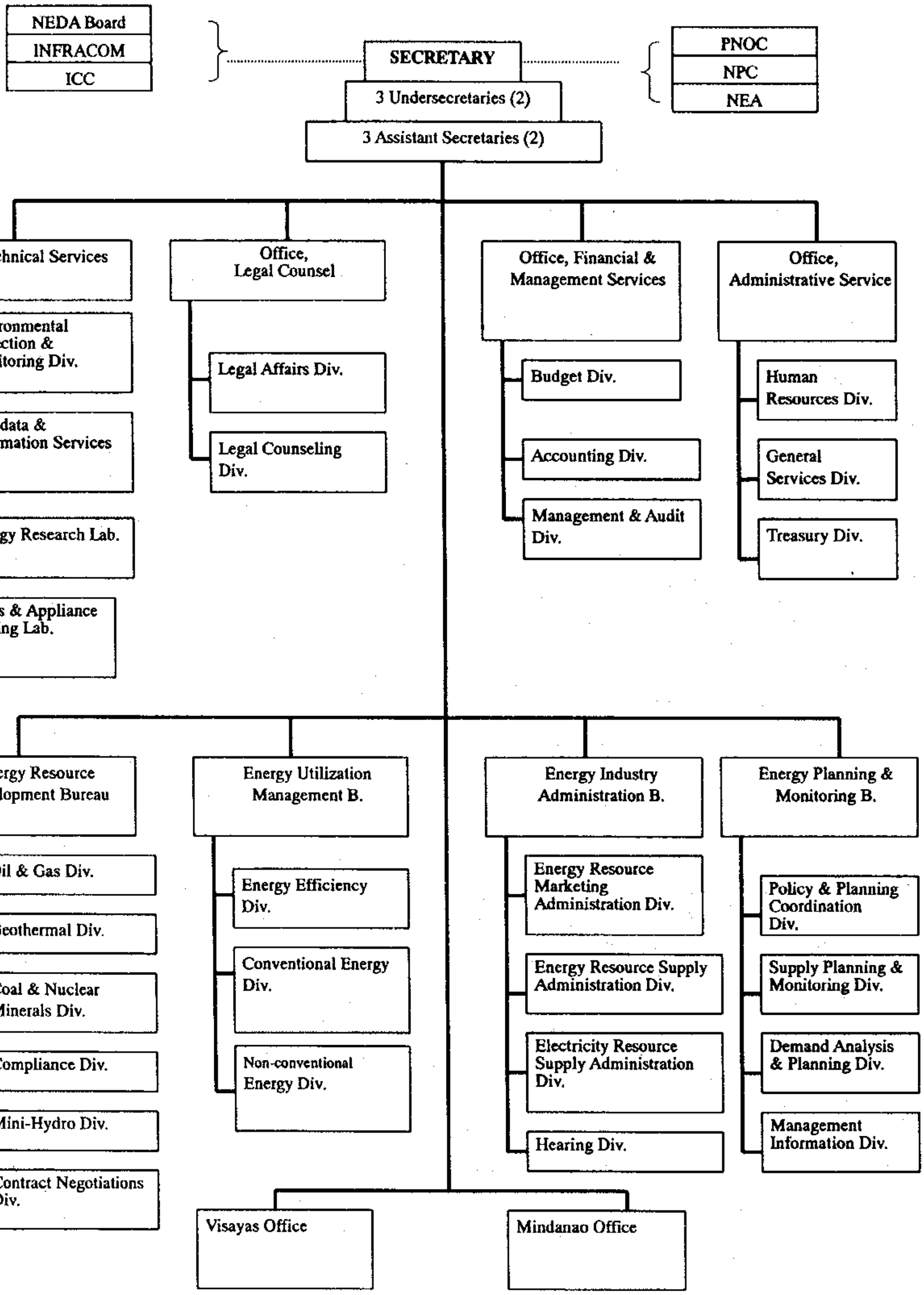
(iv) Department Circular NO. 2000-06-010 and other several circulars in 2000 specifies the penalties to the LPG Industry reflecting recent technical and commercial accounts.

(v) Department of Justice Opinion No. 95, S. 1988 (May 11,1988): first reviews the legal definition of "public utility" requiring at least 60 % of Filipino's ownership by Article XII of the Constitution, and states to the effect that a private power generation which generates electricity for its own use and which intends to sell any excess to the NPC does not constitute a public utility. This implies that an IPP is not a public utility if it sells the product to one entity only and is exempt from the jurisdiction of the ERB.

(vi) Department of Justice Opinion No. 46, S.2000 (June 6, 2000) responds to the questions on (1) whether a franchise or certificate is needed before beginning construction of underground pipelines, e.g., particularly of LPG, by Bonifacio Gas Corporation (BGC), and on (2) whether or not the current DOE has the power to grant pipeline franchise. With considerable discussions on historical statutory background on the nature of franchise and public utility, the DoJ Opinion concludes that BGC would require a grant of franchise before construction, and that, since jurisprudence holds that a franchise does not have to emanate solely from the Congress but administrative agencies may be empowered to do the same, the power to grant franchise has now been vested with the DOE as well as the Congress. (In the area of electricity, however, the newly proposed Power Industry Reform Bill stipulates that a franchise for an electric utility is granted exclusively by the Congress)

Annex 3-2

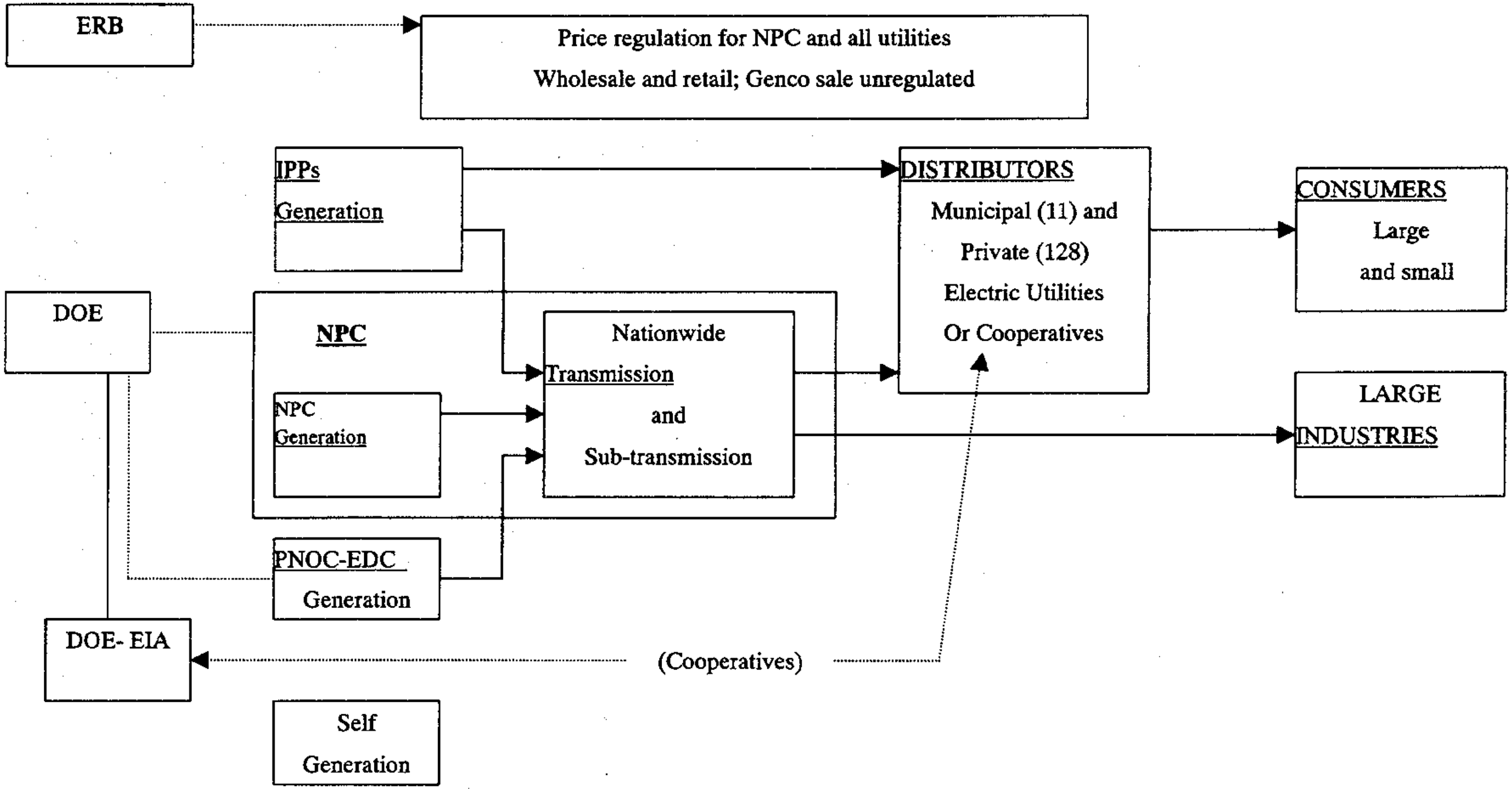
Organization of Philippine Department of Energy (DOE) (actual as of January 2001)



Note: Office= Office of the Director; B. =Bureau (Director); Div.= Division (Chief); &=and; (no.)= No. of actual positions. Source: DOE

Annex 3-3

Former Philippine Electric Power Industry Structure



Appendix 3-4

Philippine Power Industry Structure and Functions on the Electric Power Industry Reform Act of 2001

Major ERC Functions (by this Bill):

Promote competition, encourage market; discourage and penalize abuse in electric industry:

Promulgate National Grid Code and Distribution Code; ensure open/ non-discriminatory access

Enforce rules for electricity spot market

Determine cross subsidies

Establish transmission and distribution wheeling rates and retail rates for captive markets; Bear no cross subsidies;

Set lifeline rates

Penalize abuse

Annual Report to President and Congress

Monitor competition in generation market

Issue Certificate of Public Convenience

Demand side management projects

Act quasi-judicial powers

Inspect premises and books

Perform other regulatory functions appropriate

DOE Functions (RA7638 As amended by this):

Energy policy and planning

Develop/ update PEP; submit to the Congress

Prepare PDP; integrating into PEP

Assure reliability and quality

Promote private participation

Establish the Wholesale Spot Market

Establish/ administer energy programs

Supervise government energy activities

Policies/procedures for incentives for supply

Monitor private activities in power sector

Research and development programs

System of judicious incentives and penalties

Non-conventional energy develop programs

Benefits to provinces due to energy develop.

Encourage private enterprises engaged

Formulate rules and regulations

Exercise other powers necessary

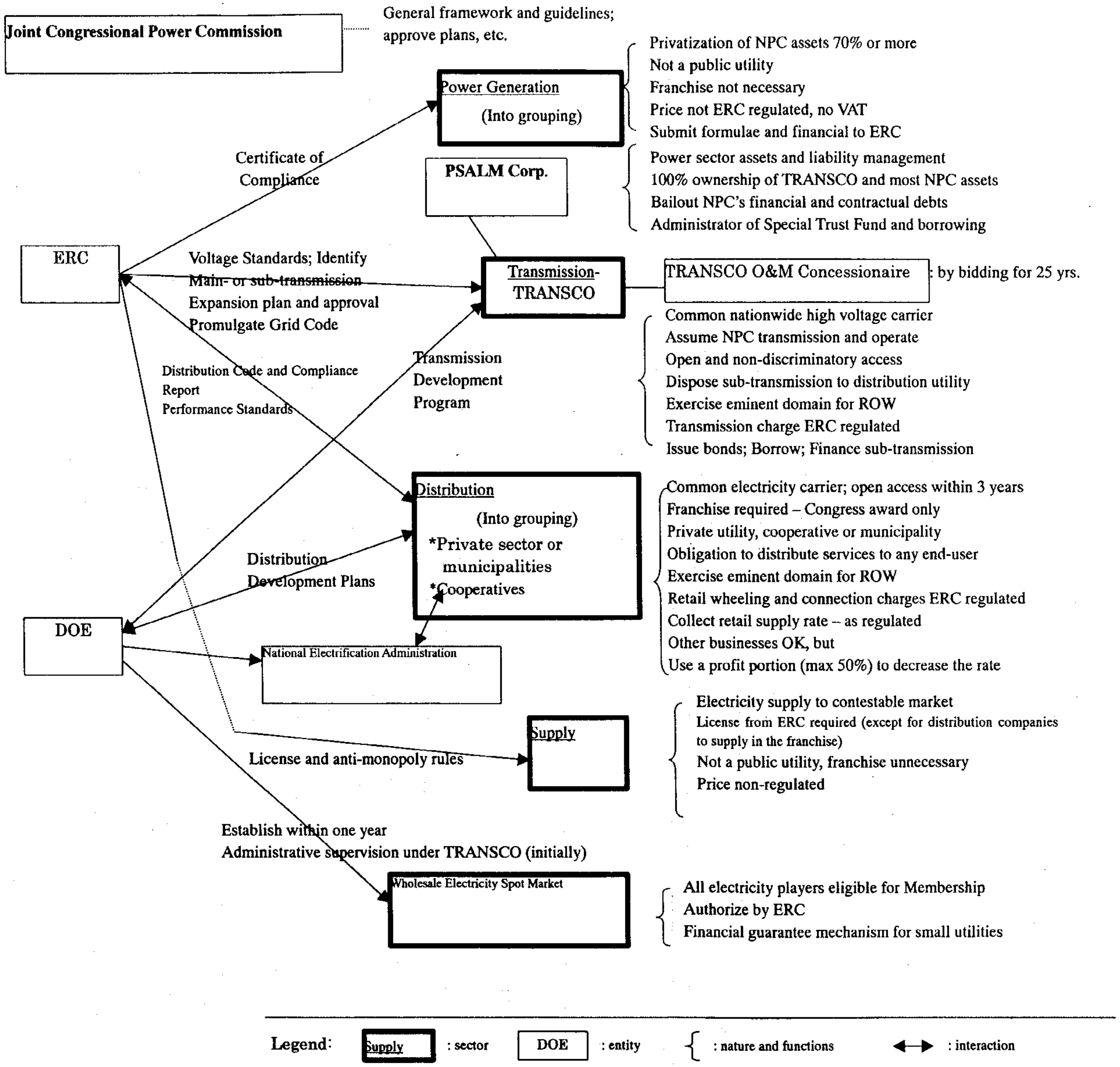
NPC Privatization through PSALM

All major assets and liabilities transferred to PSALM

PSALM formulate and implement privatization plans

NPC continue operation of unsold assets of PSALM

NPC continue missionary electrification (SMUG) and operation



Annex 3-5 Incentive Program Calculation (Trial for Low Price Case)

Types		Data		UNIt	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
LNG Price (Low Case)		LNG (net themal value based)		$/mmBtu	4.0	3.7	3.7	3.7	3.8	3.8	3.8	3.8	3.9	3.9	3.9	4.0	4.2	4.3	4.4	4.5	4.6	4.8	4.9	5.1	5.2	5.4
		HHV in mmBtu/ mscf:		1.125																						
Gas Price to Residences		(ratio)	1.00	$/mmBtu	8.15	7.84	7.86	7.88	7.89	7.91	7.98	8.06	8.13	8.20	8.28	8.50	8.73	8.97	9.22	9.47	9.76	10.06	10.37	10.69	11.02	11.26
Gas Price for Transportation		(ratio)	0.83	$/mmBtu	6.76	6.51	6.52	6.54	6.55	6.57	6.63	6.69	6.75	6.81	6.87	7.06	7.25	7.45	7.65	7.86	8.10	8.35	8.61	8.87	9.14	9.34
		(Increase)	0.00%	$/mmBtu	6.76	6.51	6.52	6.54	6.55	6.57	6.63	6.69	6.75	6.81	6.87	7.06	7.25	7.45	7.65	7.86	8.10	8.35	8.61	8.87	9.14	9.34
Gas Price for Transportation				$/mscf	7.61	7.32	7.34	7.36	7.37	7.39	7.46	7.52	7.59	7.66	7.73	7.94	8.15	8.38	8.60	8.84	9.11	9.39	9.68	9.98	10.29	10.51
2. Special Gas Account for Incentives Example Computation - Low Price Case																										
Equipment	Classification	Items	Unit	aid%			2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
NGV	Filling stations (private):	No. of stations						0	1	1	3	3	3	4	5	5	5	5	5	5	5	5	5	5	5	5
Incentive		(cumulative)						0	1	2	5	8	11	15	20	25	30	35	40	45	50	55	60	65	70	75
Program		Unit cost per station	$'1000		Equipment inflation			473	482	491	500	509	518	527	537	547	556	567	577	587	598	608	619	631	642	653
		Total cost	$'1000		rate =	1.80%		0	482	491	1,500	1,527	1,554	2,110	2,685	2,733	2,782	2,833	2,884	2,935	2,988	3,042	3,097	3,153	3,209	3,267
		Incentive Expenditure	$'1000	50%				0	241	246	750	764	777	1,055	1,342	1,367	1,391	1,416	1,442	1,468	1,494	1,521	1,548	1,576	1,605	1,634
	Public filling stations:	No. of stations						1	0	1	3	3	3	2	2	2	2	2	2	2	2	2	2	2	2	2
		(cumulative)						1	1	2	5	8	11	13	15	17	19	21	23	25	27	29	31	33	35	37
		Unit cost per station	$'1000					473	482	491	500	501	502	503	504	505	506	507	508	509	510	511	512	513	514	515
		Total cost	$'1000					473	0	491	1,500	1,503	1,506	1,006	1,008	1,010	1,012	1,014	1,016	1,018	1,020	1,022	1,024	1,026	1,028	1,030
		Incentive Expenditure	$'1000	100%				473	0	491	1,500	1,503	1,506	1,006	1,008	1,010	1,012	1,014	1,016	1,018	1,020	1,022	1,024	1,026	1,028	1,030
	NGV Conversion (Kits)	No. of conversions			Conversion cost in 2010:			2	4	6	20	50	100	200	300	400	500	600	700	800	900	1,000	1,100	1,200	1,300	1,400
		(cumulative)				Number ratio	US$	2	6	12	32	82	182	382	682	1,082	1,582	2,182	2,882	3,682	4,582	5,582	6,682	7,882	9,182	10,582
		Average cost of a kit	$'1000		Gasoline	35%	1,106	1.898	1.933	1.967	2.003	2.039	2.075	2.113	2.151	2.190	2.229	2.269	2.310	2.352	2.394	2.437	2.481	2.525	2.571	2.617
		Total cost of kits	$'1000		Diesel	55%	1,339	3.8	7.7	11.8	40	102	208	423	645	876	1,114	1,361	1,617	1,881	2,154	2,437	2,729	3,031	3,342	3,664
		Incentive Expenditure	$'1000	100%	Buses	10%	10,273	4	8	12	40	102	208	423	645	876	1,114	1,361	1,617	1,881	2,154	2,437	2,729	3,031	3,342	3,664
					Average/ vehicle =		2,151																			
Sub-Total Incentive Amount - NGV			$000					477	249	748	2,290	2,368	2,491	2,484	2,996	3,252	3,518	3,792	4,075	4,367	4,669	4,980	5,301	5,633	5,975	6,328
	Gas Price Discount	Refilling capacity /day			Max. capacity and gas quantity			259	259	517	1,552	1,552	1,552	1,552	1,811	1,811	1,811	1,811	1,811	1,811	1,811	1,811	1,811	1,811	1,811	1,811
		Average service rate %				Capacity	Gas refill	5	10	15	20	25	30	35	40	45	50	55	60	65	70	75	80	85	90	95
		No. of re-filling services /day				/ station	Nm3/yr*	13	26	78	310	388	466	543	724	815	905	996	1,087	1,177	1,268	1,358	1,449	1,539	1,630	1,720
		NG price	$/mscf	Gasoline	35%	254	12,295	7.46	7.52	7.59	7.46	7.52	7.59	7.66	7.73	7.94	8.15	8.38	8.60	8.84	9.11	9.39	9.68	9.98	10.29	10.51
			$/Nm3	Diesel	55%	294	10,362	0.28	0.28	0.28	0.28	0.28	0.28	0.29	0.29	0.30	0.30	0.31	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39
		NG Sales volume	mmcfd	Buses	10%	81	32,857	0.02	0.04	0.11	0.42	0.53	0.63	0.74	0.98	1.11	1.23	1.35	1.48	1.60	1.72	1.85	1.97	2.09	2.21	2.34
		NG Sales amount	$000	Average =	100%	258.7	13,288	48	97	292	1,148	1,448	1,753	2,063	2,776	3,208	3,661	4,137	4,636	5,160	5,728	6,326	6,956	7,618	8,315	8,968
		Incentive Expenditure	$000	20%			*/ vehicle	10	19	58	230	290	351	413	555	642	732	827	927	1,032	1,146	1,265	1,391	1,524	1,663	1,794
Sub-Total Incentive Amount : NGV+ Gas Price			$000					487	268	807	2,520	2,658	2,841	2,896	3,551	3,894	4,250	4,619	5,002	5,399	5,814	6,245	6,692	7,156	7,638	8,121
Gas	No. of Commercial co-generations		units								5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Co-generation		Unit cost	$000								1,000	1,018	1,036	1,055	1,074	1,093	1,113	1,133	1,153	1,174	1,195	1,217	1,239	1,261	1,284	1,307
Investment		Total investment	$000								5,000	5,090	5,182	5,275	5,370	5,466	5,565	5,665	5,767	5,871	5,977	6,084	6,194	6,305	6,419	6,534
tax credit		Credit amount	$000	20%							1,000	1,018	1,036	1,055	1,074	1,093	1,113	1,133	1,153	1,174	1,195	1,217	1,239	1,261	1,284	1,307
Incentives																										
	No. of Public co-generations		units								5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Unit cost	$000								800	814	829	844	859	875	890	906	923	939	956	973	991	1,009	1,027	1,045
		Total investment	$000								4,000	4,072	4,145	4,220	4,296	4,373	4,452	4,532	4,614	4,697	4,781	4,867	4,955	5,044	5,135	5,227
		Credit amount	$000	30%							1,200	1,222	1,244	1,266	1,289	1,312	1,336	1,360	1,384	1,409	1,434	1,460	1,486	1,513	1,540	1,568
Sub-Total Incentive Amount - Cogen			$000								2,200	2,240	2,280	2,321	2,363	2,405	2,449	2,493	2,537	2,583	2,630	2,677	2,725	2,774	2,824	2,875
Gas	No. of commercial gas air-conditioning		units								10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Air-conditioning		Air-condition unit cost	$000								20.0	20.4	20.7	21.1	21.5	21.9	22.3	22.7	23.1	23.5	23.9	24.3	24.8	25.2	25.7	26.1
tax credit		Investment value	$000								200	204	207	211	215	219	223	227	231	235	239	243	248	252	257	261
Incentive		Credit value	$000	20%							40	41	41	42	43	44	45	45	46	47	48	49	50	50	51	52
	No. of public gas air-conditioning		units								5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
		Air-condition unit cost	$000								300.0	305.4	310.9	316.5	322.2	328.0	333.9	339.9	346.0	352.3	358.6	365.0	371.6	378.3	385.1	392.0
		Investment total	$000								1,500	1,527	1,554	1,582	1,611	1,640	1,669	1,700	1,730	1,761	1,793	1,825	1,858	1,892	1,926	1,960
		Credit value	$000	30%							450	458	466	475	483	492	501	510	519	528	538	548	557	567	578	588
Sub-Total Incentive Amount - Air-con			$000								490	499	508	517	526	536	545	555	565	575	586	596	607	618	629	640
Natural	Industrial use	No. of gas-conversions	sets								50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Gas		(cumulative)									50	100	150	200	250	300	350	400	450	500	550	600	650	700	750	800
Conversion		Unit cost	$000								5	5	5	5	5	5	6	6	6	6	6	6	6	6	6	7
Incentive		Investment Total	$000								250	255	259	264	268	273	278	283	288	294	299	304	310	315	321	327
		Incentive amount	$000	20%							50	51	52	53	54	55	56	57	58	59	60	61	62	63	64	65
	Commercial use	No. of gas-conversion	sets								70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
		(cumulative)									70	140	210	280	350	420	490	560	630	700	770	840	910	980	1,050	1,120
		Unit cost	$000								2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3
		Investment Total	$000								140	143	145	148	150	153	156	159	161	164	167	170	173	177	180	183
		Incentive amount	$000	30%							42	43	44	44	45	46	47	48	48	49	50	51	52	53	54	55
	Residential use	No. of gas-conversion	sets								100	500	900	1,300	1,700	2,100	2,500	2,900	3,300	3,700	4,100	4,500	4,900	5,300	5,700	6,100
		(cumulative)									100	600	1,500	2,800	4,500	6,600	9,100	12,000	15,300	19,000	23,100	27,600	32,500	37,800	43,500	49,600
		Unit cost	$000								2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3
		Investment total	$000								200	1,018	1,865	2,743	3,851	4,592	5,565	6,571	7,612	8,689	9,801	10,951	12,139	13,367	14,634	15,943
		Incentive amount	$000	40%							80	407	746	1,097	1,461	1,837	2,226	2,629	3,045	3,476	3,921	4,381	4,856	5,347	5,854	6,377
	Sub-Total Incentive Amount - Gas Conv.										172	501	841	1,194	1,559	1,937	2,328	2,733	3,151	3,584	4,031	4,492	4,970	5,463	5,972	6,498
Total	NGV credit total		$000					487	268	807	2,520	2,658	2,841	2,896	3,551	3,894	4,250	4,619	5,002	5,399	5,814	6,245	6,692	7,156	7,638	8,121
Tax Credit	(Ratio to Government Take)		%					(0.33)	(0.17)	(0.53)	(1.68)	(0.88)	(0.92)	(0.94)	(1.28)	(1.43)	(1.64)	(1.76)	(1.86)	(1.86)	(2.04)	(2.16)	(2.24)	(2.33)	(2.43)	(2.55)
Incentives	Gas cogene credit total		$000								2,200	2,240	2,280	2,321	2,363	2,405	2,449	2,493	2,537	2,583	2,630	2,677	2,725	2,774	2,824	2,875
	(Ratio to Royalty)		%								(1.47)	(0.74)	(0.74)	(0.75)	(0.85)	(0.89)	(0.95)	(0.95)	(0.95)	(0.89)	(0.92)	(0.93)	(0.91)	(0.90)	(0.90)	(0.90)
	Gas air-con credit total		$000								490	499	508	517	526	536	545	555	565	575	586	596	607	618	629	640
	(Ratio to Royalty)		%								(0.33)	(0.16)	(0.16)	(0.17)	(0.19)	(0.20)	(0.21)	(0.21)	(0.21)	(0.20)	(0.21)	(0.21)	(0.20)	(0.20)	(0.20)	(0.20)
	Gas conversion credit total		$000								172	501	841	1,194	1,559	1,937	2,328	2,733	3,151	3,584	4,031	4,492	4,970	5,463	5,972	6,498
	(Ratio to Royalty)		%								(0.11)	(0.17)	(0.27)	(0.39)	(0.56)	(0.71)	(0.90)	(1.04)	(1.17)	(1.24)	(1.41)	(1.56)	(1.66)	(1.77)	(1.90)	(2.04)
	Grand Total Credit Incentives		$000					487	268	807	5,382	5,897	6,471	6,928	7,999	8,772	9,572	10,400	11,256	12,141	13,060	14,011	14,994	16,011	17,063	18,134
	(Ratio to Royalty)		%					(0.33)	(0.17)	(0.53)	(3.59)	(1.95)	(2.10)	(2.25)	(2.89)	(3.23)	(3.70)	(3.96)	(4.20)	(4.19)	(4.57)	(4.85)	(5.01)	(5.20)	(5.43)	(5.69)
C/M natural gas	Net National Government revenue		$ million				71.9	89.8	88.3	86.5	85.0	171.9	174.3	174.6	156.9	154.2	146.9	149.2	152.3	164.4	162.0	163.9	169.8	174.7	178.4	180.9
Royalty Income	Local government revenue		$ million				47.9	59.9	58.9	57.7	56.7	114.6	116.6	116.4	104.6	102.8	97.9	99.4	101.5	109.6	108.0	109.3	113.2	116.5	118.9	120.6
from C/M gas	Income tax from Gas profit		$ million				54.8	58.4	67.3	65.9	64.8	130.9	133.2	133.0	119.5	117.5	111.9	113.6	116.0	125.3	123.5	124.9	129.3	133.1	135.9	137.8
	Total Government revenue		$ million				174.6	208.1	214.5	210.1	206.4	417.4	424.6	424.0	381.0	374.5	356.7	362.2	369.8	399.4	393.5	398.0	412.3	424.3	433.2	439.2