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NATURAL GAS TARIFFS
DESIGN AND IMPLEMENTATION

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Prepared by

Merklein and Associates

Under Subcontract to

Hagler Bailly
1530 Wilson Boulevard
Suite 400
Arlington, VA 22209-2406
(703) 351-0300

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Republic of Armenia

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- Both the pipeline and distribution systems in Armenia are currently in a state of advanced deterioration

- The purpose of this study is to find the causes of this deterioration and to develop a tariff methodology and tariffs designed to restore system to normalcy

- This tariff methodology had to be such that it would inspire confidence among foreign investors This meant cost-recovery tariffs that would be objective transparent non-political and free from permanent subsidies

- The causes of the current deterioration of the Armenian natural gas industry are inadequate cash flows to operating gas companies due to a tariff methodology and financial management procedures that are rooted in the old Soviet tariff system Specific problems include

    1. The use of negotiated mark-ups on operating costs in lieu of profits
    2. The disallowance of interest payments as operating costs (now corrected)
    3. The failure to recognize property tax as operating costs,
    4. A totally inadequate valuation of the asset base leading to depreciation allowances of about 1/20th of what they should have been (now corrected)
    5. A heavy tax burden pre-empting the passing through of adequate cash flows to the operating companies

- In this report we developed a tariff methodology conformant with international standards In so doing we accepted the current structure of the gas industry, consisting of the following three major Divisions a Management Company (Armgasprom), a Pipeline Company (Transgas) and a Distribution Company (Haygas) We developed specific incremental tariffs for each company as well as a final overall tariff for four different classes of end-users

- The residential tariff at current consumption rates based on the use of a Western cost-recovery tariff methodology, is too large to be politically viable in Armenia, about three times the rate allowed under current Energy Commission Resolutions and 35% higher than the current average US residential tariff ($302/1000 CM compared to current allowable tariff of $102/MCM, and to the US average of $224/MCM)

- The reasons for the high residential tariffs under a Western cost-recovery methodology include

    1. Substantial under-capacity utilization (roughly 20% utilization of pipeline capacity and less than 10% utilization of residential distribution capacity)
    2. Residential use of natural gas in part for cooking only with a complex and expensive distribution network delivering very small volumes per end-user
    3. High taxation, including 20% VAT on the value of gas imported and delivered, plus a 25% profit tax

- Using volume projections developed by the Armenian Energy Regulatory Commission (ERC) and the Armenian gas industry, we calculated the residential tariffs for consumption volumes that would be achievable by 2001/2002 At that time and with residential consumption volumes ten times what they are now (but 74% of what they were in the 1990 peak year), residential tariffs will be cut in half compared to what they would be at today's consumption volumes However that is still 50% higher than current ERC-allowed tariffs

- The Armenian residential tariff at 2001/2002 volumes would be $153/MCM using a Western cost-recovery tariff methodology As mentioned this compares to the ERC-allowed residential tariff of $102/MCM and to US residential tariffs of $224/MCM Put differently 2001/2002 Armenian residential tariffs would come in at 68% of US tariffs but are 50% higher than currently allowed ERC tariffs

- Under the suggested average tariff of $153/MCM (actually $9 34 per month fixed fee and $102 79 variable commodity charge), average monthly gas bills per household will be

  $11 14 per month, if gas is used for cooking only
  $28 59 per month, if gas is used for cooking, water heating, and space heating

- Our recommended tariffs are listed in the box below

RECOMMENDED TARIFFS

Armgasprom Tariff
Commodity Charge at $68 80 per MCM delivered each billing period

Transgas Tariffs
Sales for Resale
Demand Charge @ $263 per Month per MCM Contract Demand
Commodity Charge @ $71 60 per MCM delivered each billing period
Transport Service
Demand Charge @ $263 per Month per MCM Contract Demand, plus
Commodity Charge @ $2 80 per MCM delivered each billing period
Contract Daily Demand equals the maximum daily delivery that occurred in the 365-day period ending with each billing period

Haygas Tariffs
Residential Service
Fixed Monthly Fee @ $9 34 per Month each billing period
Commodity Charge @ $102 79 per MCM delivered each billing period
Service Charge @ $60 00 each time service is reconnected
General Service
Commodity Charge @ $108 61 per MCM delivered each billing period or Monthly Minimum Bill of $28 02
Large Volume Service
Available to customers using more than 10,000 SCM/Month
Demand Charge @ $263 per Month per MCM Contract Demand, plus
Commodity Charge @ $78 26 per MCM delivered each billing period
Contract Daily Demand equals the maximum daily delivery that occurred in the 365-day period ending with each billing period
Special Contract Service
Available to Customers using more than 10,000 SCM per Month
Subject to special terms of service by special contract
Customer must have the capability to switch to alternate fuel within 30 Minutes upon request by Haygas
Commodity Charge @ $95 13 per MCM delivered each billing period

- The tariffs listed in the preceding box are based on a 30-year straight-line depreciation regime and on a rate of return on assets of 15%

- While our suggested tariffs appear to be high relative to current Armenian residential gas tariffs and to Armenian household incomes they are among the lowest in the world Of the 24 countries for which we developed residential tariff data our suggested tariff of $153/MCM is the fifth lowest with lower tariffs only in the Czech and Slovak Republics and in Hungary and Venezuela

- By comparison State-owned French residential gas tariffs are $430/MCM privately owned German residential tariffs are $401/MCM and privately owned cost-recovery US residential tariffs are $224/MCM

- The reason the calculated Armenian residential tariff is low compared to tariffs in the rest of the world is that we made two significant concessions in our calculations (1) we used a very low depreciation rate and (2) we used a low asset base in scaling costs from US standards to Armenian operating costs

- Our suggested tariffs include gas storage costs but they do not include rehabilitation expenditures and they do not include the installation of residential gas meters

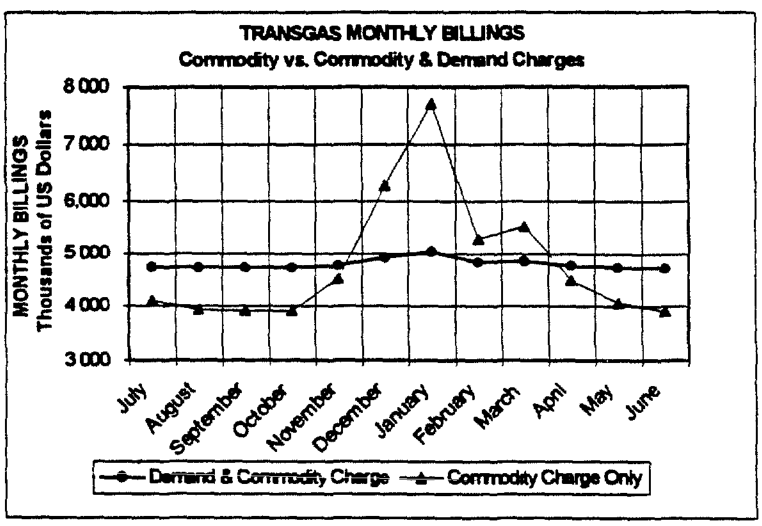
- Financed on 2-year terms, residential gas meters will cost approximately $4-5 per month

- Our suggested tariffs do not include costs incurred in installing and maintaining gas-burning consumer appliances which will have to be serviced by an independent work force of licensed technicians

- Our suggested tariffs feature demand-commodity components for pipeline tariffs and for large-volume industrial customers mostly (in terms of gas sales) but not exclusively power plants Similarly, the suggested residential tariff has a fixed monthly component and a variable commodity component

- The use of demand-commodity charges for Transgas services has the effect of

    1 Reducing the volatility of monthly billings due to volume fluctuations, including seasonal fluctuations (see graph below),
    2 Protecting consumers against sudden upswings in consumption,
    3 Protecting the pipeline against sudden declines in consumption



- Given Armenia's undoubted technical capability to restore earlier consumption rates and the Country's political will to do so we developed two options for a transitional subsidy program These options are tax concessions and mothballing of unused capacity Specific features of the programs are

  1 They are limited with respect to amounts
  2 They are limited with respect to time (3 years),
  3 They do not involve tariff adjustments per se
  4 They are not a burden to the State since they are financed through increases in tax collections accruing from our proposed changes in methodology,
  5 They are to be administered by a separate Agency (we suggested the Ministry of Finance and Economy),
  6 They are transparent and publicized

- We prefer tax concessions over mothballing since tax concessions are funded by windfall tax receipts accruing to State under our proposed Western tariff methodology, whereas the burden of mothballing is carried one third by the State and two thirds by the gas companies that can ill afford this shortfall in cash flow

- We also discussed but did not offer specifics, regarding temporary reductions in rates of return if the new joint-venture partner, the Russian pipeline company Gasprom, is prepared to go along in the interest of securing a long-term market outlet These reductions could be achieved through an adjustment of structural- and country-risk components

- Tariffs other than residential come in at seemingly acceptable rates i e they do not need subsidies Average cost-recovery tariffs at 2001/2002 projected volumes are listed in the following Table, $/MCM

	Pipeline Sales	Residential Sales	Small Industrial & Commercial	Power Plants	District Heating
Currently ERC-Allowed	$69	$102	N/A	$79	$55 (a)
Cost Recovery	$92	$153	$109	$97	$95
US Tariffs	$115	$224	$191	$121(b)	N/A

N/A Not Applicable
(a) District Heating Tariff currently has no cost or tax allowance of any kind
(b) Does not include third-party tariffs under by-pass arrangement

- In summary the Armenian gas industry can only be rehabilitated if the operating companies can generate private financing from lenders These lenders will only provide funds when they see tariffs high enough to provide the gas industry with cash flow from its customers to pay the principal and interest on the borrowed money We believe that the tariffs recommended in this report are the minimum required to meet the lender's expectations If the gas industry cannot meet this expectation, we only see further deterioration of the system with attendant hazardous conditions to the welfare of the people of Armenia

Chapter
1

Existing Natural Gas System

Historical Background

Purpose of the Project

The current natural gas system in Armenia reflects user and supply patterns that were relevant under the integrated energy system of the former Soviet Union With Armenia now operating as an independent energy unit its natural gas pipeline and distribution system needs to be re-balanced and upgraded In addition, the current presence of one Western petroleum explorer/producer who may well become a user of the Armenian gas pipeline system the need to attract other exploration companies, and ongoing negotiations with a major international natural gas pipeline company mandate the establishment of an operating and tariff methodology that will inspire confidence among foreign investors

The international petroleum industry has settled and become comfortable with a tariff system that has the following characteristics

- Cost-recovery tariffs, providing for full recovery of reasonable operating and capital costs and for an equitable rate of return on investment

- Transparent and objective tariffs and procedures Suggested tariffs are developed by pipeline and distribution companies and submitted for approval at public hearings to an independent regulatory body, using a published accounting system that meets international standards The methodology in arriving at tariffs is such that different parties to the system will come up with very similar rates if they do the calculations separately

- A non-political tariff system cross-industry subsidies cross-line subsidies cross-user subsidies or social subsidies are not permitted to enter the tariff structure To the extent that some subsidies (especially social subsidies) are politically or otherwise unavoidable, they are administered through separate, transparent and explicit subsidy programs rather than through hidden or overt increases in pipeline and distribution rates

Sizable investments will be needed in the Armenian natural gas pipeline and distribution systems to bring them up to international standards and to expand them to accommodate expected changes in domestic transport patterns and transit capacities The Government of Armenia will be competing with many other oil and gas consuming and transit nations to attract the needed capital Those nations that are capable of achieving the transition to internationally acceptable operating and financial regimes will succeed in attracting the required capital

It is the purpose of this USAID-sponsored Armenian Natural Gas Tariff Project to work with and develop recommendations for the newly-created Energy Regulatory Commission regarding the adoption of a viable tariff system that will serve the nation for years to come

Early Natural Gas Supplies

Among the Republics of the former Soviet Union Armenia had one of the highest levels of gas consumption In the residential sector the market penetration was the highest of all former Soviet Union Republics with 83 3% of all residents receiving gas in some form or other Of these 61 5% used natural gas delivered by distribution systems and 21 8% used bottled gas

The importation of natural gas into Armenia began in 1957 the date at which the Yerevan branch of the Trans-Caucasian Gas Main Department began operations In 1970 that branch was renamed "Armtransgas Industrial Association" which involved in its structure three regional subsidiaries, the Abovian, Vanadzor and, from 1972, the Goris Gas Main Maintenance Departments "Armtransgas" was responsible for the importation of natural gas into the Republic and for the operation of the gas main pipeline

At the same time, the "Armgas State Committee on Gas Supply" was established whose responsibility was chiefly the distribution of natural gas A total of 10 urban and regional gas distribution departments were established within "Armgas" In 1974 a new gas sales activity was added when the "Liquefied Gas Industrial Enterprise" was established whose task it was to import liquefied gas and to distribute it in regions that did not have access to natural gas In addition, Armgas was put in charge of the underground storage of natural gas then under construction in the Abovian Region The operation of all of these enterprises was subsequently absorbed into one vertically integrated organization called the "Armtransgas Association" The company underwent several name changes since then It is carried under the name of "Armgasprom" throughout this report

Until 1972 Iran was the exclusive source of gas for Armenia Iranian gas was transported through Azerbaijan The subsequent discovery of giant natural gas fields in the former USSR led to the importation of natural gas into the Republic through an interconnected nationwide gas transportation system operating throughout the USSR At that stage the Armenian gas supply system permitted the importation of natural gas through three main pipelines from Azerbaijan, which are listed below

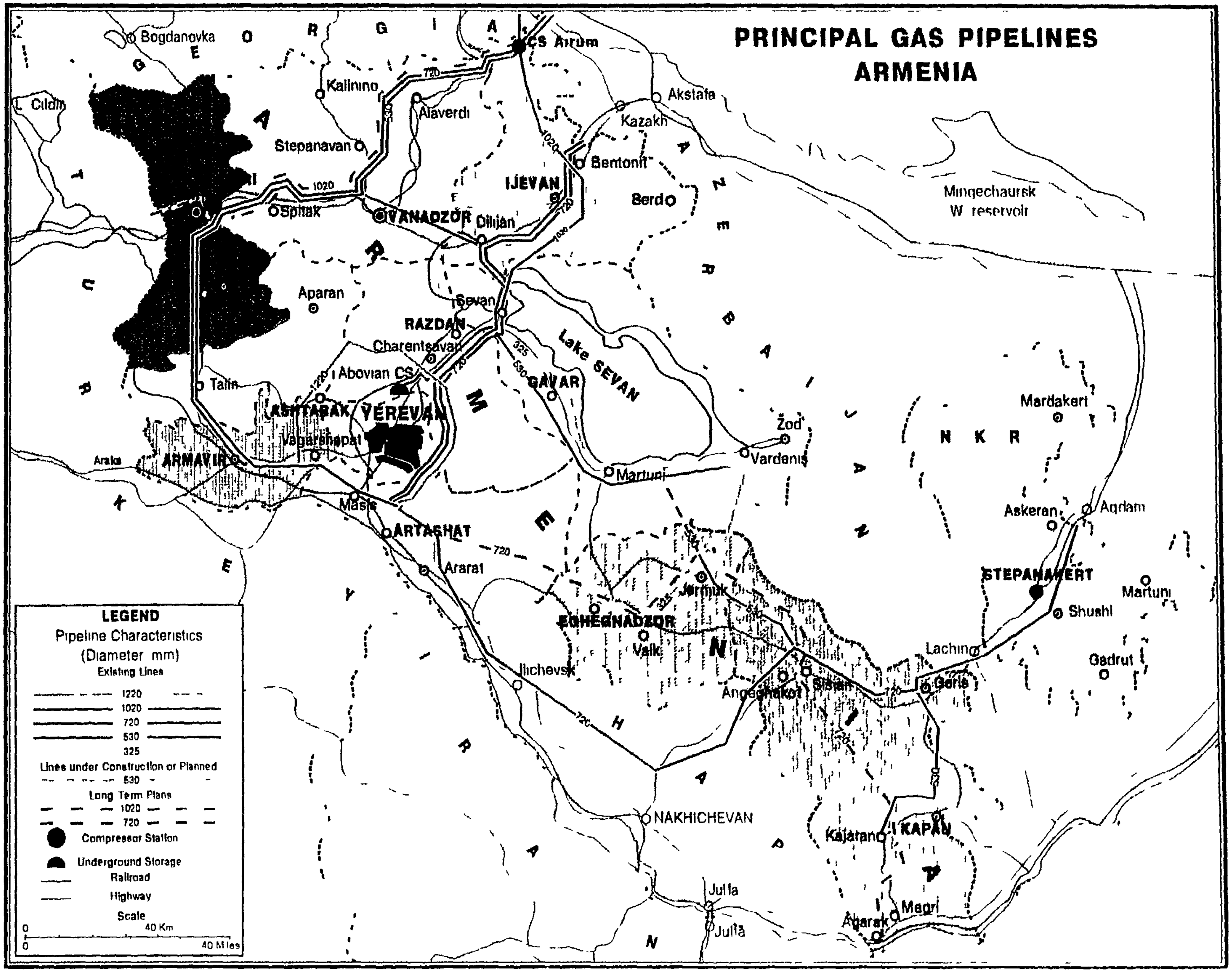
1 Kazakh - Idjevan - Yerevan (1000 mm diameter, approximately 40"),

2 Kransny Most (Azerbaijan) - Alaverdi - Kirovakan - Gyumri (700 mm diameter approximately 28"), and

3 Yevlakh - Stepanakert - Goris - Sisian - Nakhichevan - Ararat (500 mm diameter approximately 20")

In 1983 the construction of the Northern Caucasus-Trans-Caucasus main gas pipeline was begun That line is the only non-Azeri link to Russian and Turkmenistan gas, through Georgia The line diameter is 1000-1420 mm (40 - 56"), depending on location The construction of that vital link to foreign gas was completed in 1993 A map of the pipeline system currently in operation in Armenia is shown in Figure 1

In 1988 the conflict between Azerbaijan and Kharabakh brought on the embargo of Armenia by Azerbaijan Since all gas import lines ran through Azerbaijan at the time, the disruption of gas deliveries through Azerbaijan plunged Armenia into an economic crisis In 1991, the disintegration of the USSR deepened the crisis as all economic relations were severed the markets were redirected and the Republic had to search for a way out This economic crisis resulted in the near-collapse of industry and in a substantial reduction of the incomes and paying ability of the general public The resulting nonpayment for consumed gas forced further reductions in gas imports By 1994 gas



ARMGASPROJECT Institute

Figure 1

supplies to the residential sector had to be shut down altogether The remaining natural gas consumers in the Republic can be grouped as follows

the power system
the industrial system
district heating
priority community needs (hospitals schools etc)

Estimated historical gas consumption volumes in the Republic are listed in Table 1 by consuming subsector As that Table shows, the natural gas industry continues to be in disarray 1995 deliveries were up from 1994 but, at 1 46 Billion Cubic Meters (BCM) per year, they were still less than a quarter of the peak deliveries of 1989 By 1996 annual deliveries had slipped to 1 12 BCM and they had risen only slightly, to 1.26 BCM, by 1997

Table 1
NATURAL GAS IMPORTS AND CONSUMPTION IN ARMENIA

	1987	1988	1989	1990	1991	1992	1993	1994	199-
	Millions of Cubic Meters								
Gas Imports to Armenia	5120	5754	6328	4712	4153	1879	801	868	1458
- Gas Exports	200.2	266 6	308 5	375 3	349 8	76 4	-	-	-
Sales to	4776	5366	5756	4292	3713	1711	768	791 3	1372
- Armenergo	1104	1583	2089	974 6	1025	1073	692	682 4	1175
- Yerevan City District Heating	201 0	198 0	193 7	163 4	95 4	8 4	0 6	7 8	42 0
- Other District Heating	327 8	325 7	268 3	278 8	180 3	7 7	0 01	2 2	14 9
Residential Consumers	1197	1251	1315	1355	1207	412 4	12 8	-	3 8
- Industry including	1620	1668	1582	1221	993 2	188 4	59 5	98 9	136 8
Chemical	120 2	113 3	105 6	26 1	39 5	13 0		14 8	23 2
Light Industry	79 8	89 5	71 6	58 8	44 8	15 7		0 86	1 0
Electro-Technical	119 2	132 2	126 2	125 5	97 7	40 0		-	-
Agricultural	97 0	100 0	98 6	85 2	80 4	6 0		15 2	19 0
Transport	29 1	30 4	28 6	29 3	21 3	1 7		0 2	0 5
Construction	69 1	69 3	70 6	52 0	50 3	7 0		0 1	1 9
Construction Materials	206 3	203 2	217 8	114 3	159 6	26 0		31 0	50 0
- Hospitals, Schools etc	325 1	345 6	308 7	299 5	211 7	21 5	16 5	10 0	56 9
Internal Consumption	29 3	27 0	94 4	20 0	17 1	15 0		5 6	7 2
- Losses	118 7	160 5	187 1	149 5	108 7	80 9		46 2	67 2

The natural gas delivery system as a whole has been, and continues to be unable to account with precision for sector-by-sector gas consumption since gas meters are installed only at industrial and other significant enterprises There has been no gas metering in the residential sector which, at present receives very little natural gas In the past, residential gas consumption was calculated according to norms established by experts of the gas distribution company which goes under the name of "Haygas" throughout this report The residential-sector norms included as consumption and billing parameters the number of persons in a household, the types of appliances used (with imputed tariffs for gas stoves approximately three times as high as those for water heaters), and the surface areas of dwellings which were used to estimate the amount of gas used for space heating Normative gas consumption calculations were performed at the beginning of each year and submitted to GosPlan (now the Ministry of Finance and Economy), where they were used to estimate individual and aggregate household gas consumption for the year It is obvious that such a "metering" system could not meet the more rigorous standards of market-oriented consumption accounting One of the most urgent prerequisites for the resumption of gas deliveries to the residential sector is the installation of gas meters for each household The Government is now firmly committed to move in that direction

In 1994 the Republic of Armenia in an attempt to secure reliable gas supplies from abroad signed a Gas Purchase Agreement with Turkmenistan That Agreement permitted Armenia to pay for part of its gas imports through barter which eventually rose to 60-75% of the total value of gas imports At first all natural gas commodity bartering was performed by the "Armcontract Trade Agency" within the Ministry of Materials Resources By 1995 a new Agency was created for that purpose the "Armturtrade State Enterprise" Jurisdiction over the enterprise was assigned to the Ministry of Energy

Part of the cash payments made to Armgasprom by industrial gas consumers and thermal power plants were forwarded to Armturtrade State Enterprise where they were used to finance the purchase of locally produced barter goods These barter goods were then shipped to a foreign trade subsidiary of Armgasprom which would forward them to the foreign supplier in partial payment for delivered natural gas As always, commodity bartering is extremely inefficient and essentially non-transparent In Armenia, some of the fall-outs of barter trading include substantial non-payments debt accumulations and a confusing array of cross-indebtedness among various enterprises throughout the Republic The Government of Armenia is committed to replacing all current barter arrangements with cash transactions

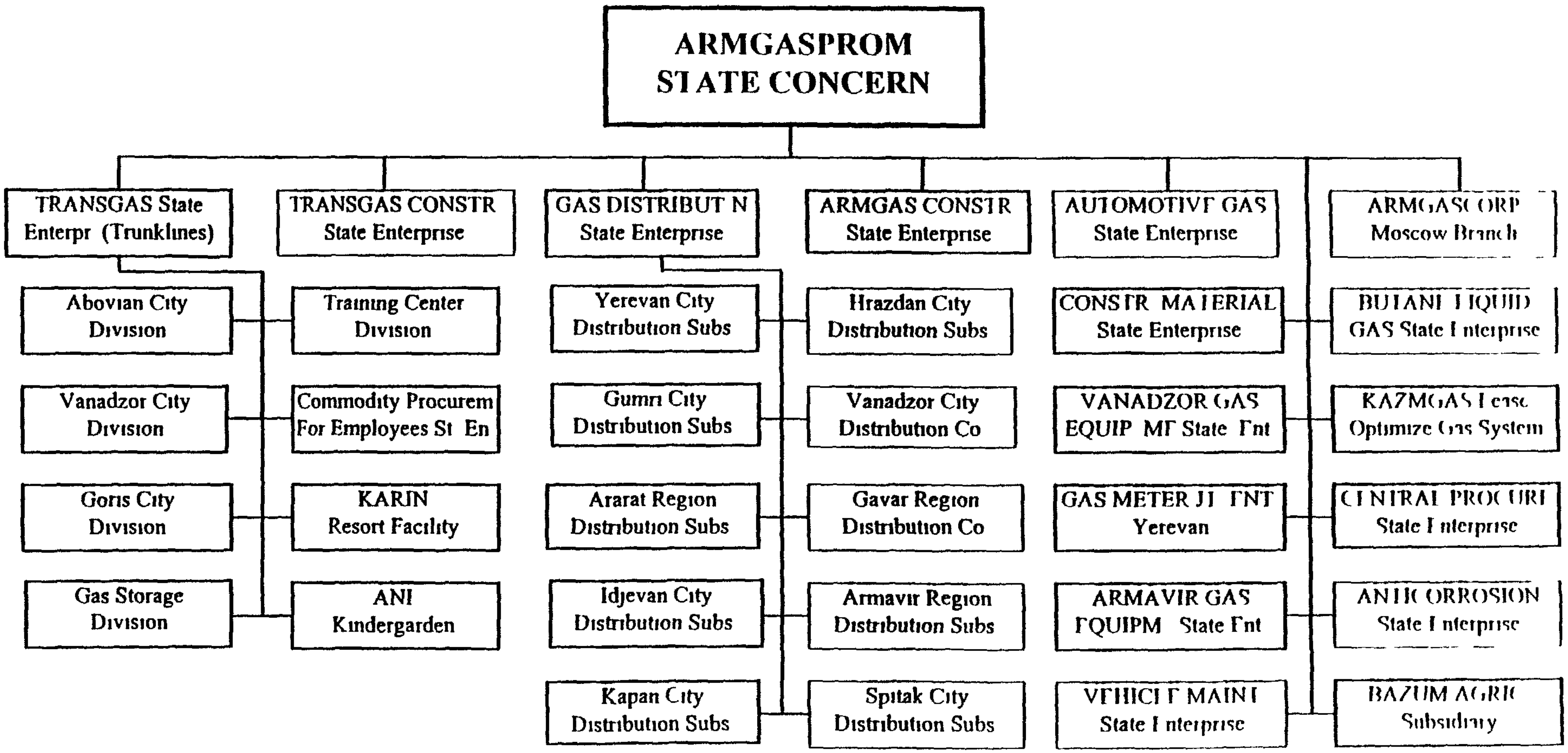
Armgasprom Organizational Structure

The Armgasprom State Concern used to be a vertically and horizontally integrated natural gas monopoly covering 35 organizations with a total staff of 6,550 employees The functions of the Armgasprom State Concern included the purchase of natural gas from importers, gas transmission by high-pressure gas pipelines and medium-pressure gas distribution to selected industrial consumers natural gas storage liquefied gas imports storage and distribution through low-pressure delivery networks sale of compressed gas for motor fuel, construction and operation of pipeline systems gas equipment manufacturing, and others The various enterprises within the old Armgasprom structure are shown in Figure 2

In an earlier USAID-financed report, entitled *Organization and Structure of the Natural Gas Sector Review and Recommendations*, we recommended that with the exception of a transmission company, Transgas (which would include storage operations), a national distribution company, Haygas and a recently added management company, Armgasprom, the Government either absorb or spin off all auxiliary enterprises To date, two of the 15 auxiliary companies have been spun off (the Kazmgas Lease Optimization Company and the Bazum Agricultural Subsidiary) The fate of the remaining auxiliary companies is at present uncertain Since the Government is currently involved in merger negotiations with an interested international gas pipeline company and the disposition of these auxiliaries is itself a negotiating point, we cannot predict the ultimate fate of the auxiliary companies We do want to make the point, though, that the cost of non-essential auxiliaries, if retained by the Armgasprom State Concern, should not be charged out through the tariff structure The end-user of natural gas should not be asked to provide financial support, through higher tariffs to support auxiliary manufacturing or other operations not directly related to the transmission or distribution of natural gas

The Energy Regulatory Commission

On June 9, 1997, the Government of Armenia enacted an Energy Law which recognizes the monopolistic nature of the gas industry and provides a regulatory oversight mechanism through the establishment of the Armenian Energy Regulatory Commission ("ERC") Among other things, the Energy Law defines general tariff setting-principles which include the concept of full-cost recovery, it permits the establishment of different tariffs among different customer groups and it prohibits subsidies between different consumer classes



ARMGASPROM STATE CONCERN
TRANSGAS State Enterpr (Trunklines)
Abovian City Division
Vanadzor City Division
Goris City Division
Gas Storage Division
TRANSGAS CONSTR State Enterprise
Training Center Division
Commodity Procurem For Employees St En
KARIN Resort Facility
ANI Kindergarden
GAS DISTRIBUT N State Enterprise
Yerevan City Distribution Subs
Gumri City Distribution Subs
Ararat Region Distribution Subs
Idjevan City Distribution Subs
Kapan City Distribution Subs
ARMGAS CONSTR State Enterprise
Hrazdan City Distribution Subs
Vanadzor City Distribution Co
Gavar Region Distribution Co
Armavir Region Distribution Subs
Spitak City Distribution Subs
AUTOMOTIVE GAS State Enterprise
CONSTR MATERIAL State Enterprise
VANADZOR GAS EQUIP MF State Ent
GAS METER JT ENT Yerevan
ARMAVIR GAS EQUIPM State Ent
VEHICLE MAINT State Enterprise
ARMGASCORP Moscow Branch
BUTANE LIQUID GAS State Enterprise
KAZMGAS Lease Optimize Gas System
CENTRAL PROCURE State Enterprise
ANTICORROSION State Enterprise
BAZUM AGRIC Subsidiary

Figure 2

As regards natural gas Section IV of the Energy Law stipulates that the ERC as its principal objective provide a reliable and safe supply at reasonable rates To grant a measure of independence to the ERC the Law provides that the Commission cannot be dissolved except through amendment of the Law itself Section IV also calls for open hearings with public access and it prohibits ownership of financial interests for ERC Members in any organization under its jurisdiction

Section V of the Energy Law deals with tariffs It states in Article 34 that the Energy Commission shall approve or disapprove tariff applications submitted by an Operating Licensee Decisions regarding such approval or disapproval are to be rendered within 90 days of the filing date of a Licensee's request for a change in tariff In addition, the ERC is given the right to review tariffs on its own initiative

On August 8 1997, the ERC issued its Resolution Number 7 on natural gas tariffs This Resolution established a two-tier maximum tariff, setting it at $79 10 per Thousand Cubic Meters (MCM), or roughly 39 6 drams per Standard Cubic Meter (SCM), for large consumers, and at 51 0 drams per SCM (or $102 0 per MCM) for small and residential customers The higher residential tariff was to cover the cost of resuming gas supplies to the consumers and the cost and installation of gas meters

A subsequent Resolution, Number 14, issued on October 24 1997, served to clarify the natural gas tariff in light of the restructured gas supply company The share of the tariff accruing to each of the three component companies (the Management Company "Armgasprom", the Transmission Company "Transgas", and the Distribution Company "Haygas") was defined for that part of the natural gas that was to be delivered to large customers The actual shares are listed in Resolution Number 14, as are the calculations to be used in arriving at them As a basis for Resolution 14, the ERC issued a set of cost data for each component company that was to serve as the basis for its tariff calculations That Table is reproduced here as Table 2

When this team was asked to assist in the establishment of short-term natural gas tariffs and a viable, Western-oriented tariff methodology, it was decided early on in consultation with a work group consisting of representatives of the ERC and the component gas companies to use Table 2 as a starting point for all subsequent tariff work Table 2 is the ERC's best estimate of the pipeline and distribution company costs, and of the overall administrative costs of the system The tariff work that follows from that plan is the topic of Chapter 2

Table 2

GAS INDUSTRY OPERATING EXPENSES FOR 1998
ERC ESTIMATES

Thousands of Armenian Drams

	OPERATING EXPENSES	TOTAL	ARM GASPROM	TRANSGAS	ARMGAS
1	Supplies and Raw Materials	130 000	10 000	100 000	20 000
2	Salary Fund	721,000	100 000	221 000	400 000
3	Social Allocations (Insurance)	259,560	36 000	79 560	144 000
4	Internal Electricity Consumption	136 000	18,000	96 000	22 000
5	Fuel	139 000	20,000	74 000	45 000
6	Automotive Expenses	40,000	8 000	20 000	12 000
7	Depreciation	177,000	8,000	119 000	50 000
8	Personnel Training	9,800	1,000	3 800	5 000
9	Travel Expenses	41 400	28,000	10,000	3 400
10	Rent	11,000	1 000	0	10 000
11	Repairs and Maintenance	1 712,446	100,000	835 428	777 018
12	Cathodic Protection	30,000	0	7 400	22 600
13	Telephone Service	52 000	34 000	8 000	10 000
14	Local Utility Charges	20 000	4 000	10 000	6 000
15	Audit Service	46 000	20,000	9 000	17 000
16	Banking Services	349 000	332 000	6 000	11 000
17	Interest On Short-Term Loans	100 000	100 000	0	0
18	Marketing Expenses	50,000	50 000	0	0
19	Protection From Natural Calamity	82 000	3,000	46 000	33 000
20	Custom Fees	140 000	140,000	0	0
21	Other Expenditures	48 700	22,000	12 000	14 700
22	Rehabilitation Residential Sector	0	0	0	0
23	**Total Operating Expenses**	**4,294,906**	**1,035,000**	**1,657,188**	**1,602,718**
24	Profit (Including Interest on L-T Loans)	1 515 856	1 215 000	132 574	168 282
25	**Total**	**5,810,762**	**2,250,000**	**1,789,762**	**1,771,000**

Notes

Transmission Losses
Allowable Technical Losses - 3 0%
Gas For Internal Usage - 0 8%
Allowable Losses and Internal usage - 3 8%
Distribution Network
Allowable Losses and Internal usage of Gas - 1 68%
Annual Delivery Volume - 1 600 Billion SCM
Import Price of Natural Gas $55 00 per MCM plus VAT of $11 00
Natural Gas Tariff to End User (Resolution 14)
-above 10 000 SCM per month - $79 10 per MCM
-less than 10 000 SCM per month - 51 drams per SCM (or $1 02 per MCM at Current Exchange Rate)
Interest on Long-Term Debt Included in Armrosgasprom Profits 800 000 (Line 24)
SCM - Standard Cubic Meter @ 20° C and 1 Bar of Pressure
MCM - Thousand Standard Cubic Meters

Chapter

2

Introducing Change

Western Tariff Methodology

The Base Case

As mentioned, one of the first moves of the Hagler Bailly tariff team was the creation of a work group That group was chaired by Dr Hovsepyan, Commissioner at the ERC and that Body's designated spokesman in the area of natural gas pipeline and distribution company regulation Other Armenian work group members were representatives of the component natural gas companies and of course members of the Hagler Bailly tariff team

The purpose in establishing such a team was to make sure that (1) the responsible Armenian Officials were being consulted step by step so that the Hagler Team would not move too far out in a direction that would eventually prove to be unacceptable to the Government of Armenia (2) the Hagler Team would have the resources to develop a full understanding of opportunities and limitations in the Law especially the Armenian Tax Law, and (3) the Armenian Officials would develop a full understanding of the reasons why certain model excursions would be made and what the implications of such excursions might be for Armenia

We started with the ERC cost data shown in Table 2 which was prepared in compliance with Article 46 of the Energy Law of the Republic of Armenia The first step in our gradual movement towards a Western-type regulatory setting was to re-write the original cost data the way they would be presented by a US or Canadian natural gas company We preserved the structure of the Armenian gas industry as designed and implemented in late 1997 There would be an Administrative or Management Company, Armgasprom, which would be responsible, among other things, for all financial transactions with outsiders There would be a Transmission Company, Armtransgas or simply Transgas responsible for shipping and storing all natural gas in Armenia And there would be a Distribution Company Haygas Because we anticipated that there would eventually be direct deliveries of gas to major industrial consumers, possibly by-passing the distribution function we agreed with the general approach suggested by the ERC that separate tariffs would be needed for each component company

Schedule ERC listed at the end of Chapter 2 along with other schedules reflects the ERC cost structure as originally proposed by the Commission Several things come to mind upon inspection of this Schedule First long-term interest charges are not carried as a cost Instead they are included in an item we labeled "profit before profit tax (including interest on long-term debt)" line 60 on the ERC Schedule Second, there was no charge for property taxes Third the charge for depreciation was extremely low 177 million drams ($354,000) for the book value of the entire capital investment in all pipeline and distribution assets throughout Armenia (Line 24) Fourth, there was no reserve for bad debts Fifth the profit was a mark-up of operating and maintenance costs In the case of Transgas the mark-up was 8 0%, in the case of Haygas, the mark-up was 10 5% The mark-up for Armgasprom was 117 4% counting the long-term interest of 800 000 drams and 40 1% after deduction of long-term interest charges (Lines 23 and 24 Table 2) Finally, operating and maintenance costs appeared to be lower than what they should be in comparison with Western operating experience

In setting up our tariff schedules we opted to treat each company as though it received the gas spent funds on it in treating it in accordance with its respective function paid taxes on it and then sold it to the next company down the line Thus the gas was taken into custody at the border by Armgasprom passed on and billed to Transgas with Armgasprom's expenses profits and taxes added into the bill Transgas would then ship the gas to Haygas and it would add its expenses profits and taxes to its invoice to Haygas which would do the same with respect to the end-user The incremental tariff at each company stage was calculated by charging actual costs incurred to the volume of gas sold i e after adjustment for internal consumption and technological gas losses The overall tariff to the end-user then is the sum of the cost of gas at the border including the VAT tax plus the incremental tariffs resulting from services performed by the component companies Using a slightly different import volume, we came up with a tariff of $78 60 per MCM, compared to the Resolution 14 tariff of $79 10 per MCM

Because Resolution 7 cites some tariffs in terms of US Dollars per MCM and others in terms of Armenian drams per SCM, we presented both units in Schedules ERC through F-4 We also calculated the claims of various parties to the funds generated through the importation and sale of natural gas in Armenia These claims were expressed in terms of dollar values and as a percent of total dollar transactions For example in accordance with the cost and profit treatment suggested by Schedule ERC the State claims 17 9% of all funds generated by the importation and sale of gas in Armenia (Line 84) As expected, most of these funds go to the importer, 74 0% As regards funds generated and spent inside Armenia the Government claims 68 9% through taxation and 7 0% by virtue of being the exclusive shareholder for a total of 75 9% (Line 92) The rest less than a quarter is absorbed as operating and maintenance costs by the component companies We believe that such a high tax burden, which is one of the principal causes of the shortage of operating funds is unintended and not fully understood This tax burden is a major contributor to the deterioration of the natural gas delivery system in Armenia

We also made a point of showing explicitly in Schedule ERC the rate of return on assets and the depreciation accrual rate of each component company Based on current book values (old Armenian standard) the rate of return of Armgasprom is 4796% when the long-term interest is included in profits (Line 95) and a still very substantial 585% without the long-term interest This surprising return is the result of relating what would appear to be a reasonable profit, based on volume to a very small asset base The rate of return on assets of Transgas, by contrast is small 3 59%, compared to a more realistic 10 4% for Haygas The depreciation accrual rates for the two operating companies Transgas and Haygas are reasonable by Western standards, at a little over 4% but they are high for Armgasprom at 42%, suggesting an average life cycle for that company's assets of 2 5 years

As mentioned Schedule ERC reflects the treatment of natural gas handling expenses as considered by the Energy Regulatory Commission Subsequent schedules ERC-2 through F-2 reflect step-by-step changes in our attempts to bring the original Commission treatment in line with Western practices

Moving Toward a Western Tariff Methodology

Schedule ERC-2: Treating Long-Term Interest as a Cost

The only change from Schedule ERC was the removal of long-term interests from profits and the posting of that item as a separate cost item of Armgasprom Because long-term interest payments under this treatment are no longer included in profits there would be no profit tax on these interest payments Accordingly, we reduced the profit taxes originally proposed by the ERC The VAT tax is also reduced since it now is applied to a reduced base that now longer includes a profit tax on long-term interest payments All in all the incremental tariff of Armgasprom is reduced under this scenario from $3 23 per MCM to $2 73 (Lines 76 Schedules ERC and ERC-2) Overall the tariff to the end-user under this scenario is reduced slightly from $78 60 per MCM to $ 78 07 (Lines 75)

The rates of return are not affected by this treatment except of course the return to Armgasprom which is substantially reduced since its principal "profit' component has been removed Depreciation accrual rates remain unaffected under this scenario but the State's claim to intra-Armenian funds is reduced from 75 9% to 70 2% because long-term interest payments are no longer shown as part of profits and therefore, are not subject to the country's 25% tax on profits The winner in this scenario is the operating companies whose collective claim rises from 24 1% to nearly 30% This is a substantial improvement, but it is still not enough by far to assure viable operations

Schedule A-2: Introducing Property Taxes, Based on Old Assessments

Schedule A-2 serves the purpose of moving property taxes into the cost structure and ultimately into the natural gas tariffs in Armenia We are not suggesting that property taxes (or rates of return for that matter) be based on book values inherited from the former Soviet accounting system These values total $8 0 million for the entire Armenian gas delivery system For Armgasprom for example the listed book value of current assets is $38 000 Applying the Armenian property tax rate of 0 6% to the total book value of current assets based on the former Soviet assessment, yields an additional cost of 24 million drams, or $48,000, hardly enough to make a dent in that company's or the overall tariff which rises ever so slightly, from $78 07 to $78 10 per MCM The State's claim on intra-Armenian natural gas funds remains virtually unaffected under this scenario and the component companies' rates of return and depreciation accrual rates remain unchanged

Schedule B-2: Introducing Property Taxes, Based on Current Assessments

Since the current net book value of the natural gas delivery system in Armenia is one of the most important cornerstones of Western tariff methodology we have independently developed an assessment of that value This work is reproduced in Appendix A Suffice it here to point out that our assessment is in line with a recent assessment performed by the Armgasproject Institute of Armenia, a research institute specializing in natural gas issues Their suggested 1998 book values for the three component companies are reproduced on Lines 33 and 34 of Schedule B-2

Because the Armgasproject Institute values are in line with our work and because these values have been used in sensitive Armenian merger negotiations with the Russian gas company Gasprom we agreed to accept their values in our work Schedule B-2 reflects the changes in tariffs and other parameters resulting from the replacement of the old Soviet asset values with the new 1998 values and the application of property taxes to these new values As we will see in later Schedules (C-2 and E-2), switching to a methodology that uses asset values as a basis for depreciation and rates of return will make a substantial difference in tariffs and company claims In terms of Schedule B-2 though where the change from Schedule A-2 merely involves increased property taxes, the tariffs are affected, but not significantly the overall tariff to the end-user rises by $1 05 per MCM (about 1 3%, less than 3 cents per Thousand Cubic Feet or MCF) from $78 10 to $79 15 per MCM

However Western-style rates of return are significantly affected by this 30-fold increase in asset values since the returns are based on these asset values Thus through the mere shifting of valuation bases the rates of return decline to 9 0% for Armgasprom and to fractional percentages for the other two gas service companies (Line 95) Depreciation accrual rates are similarly affected For Armgasprom, the depreciation accrual rate declines to 1 43%, implying an asset life cycle of 69 years on a straight-line depreciation regime For Transgas and Haygas, the depreciation accrual rates are a fractional percent What these numbers say apart from the extreme life cycle implication, is something we have known intuitively for a long time which is that depreciation allowances are much too low robbing the operating companies of an important source of cash flow In addition the increased asset base raises the asset-related returns to the natural gas companies and through them their tax obligations As a result the State's claim on intra-Armenian funds is increased at the expense of the operating companies whose percentage claim drops from 29 7% under the old asset valuation to 28 3% now (Line 89)

Schedule C-2: Introducing Depreciation Based on Current Assessments

In our discussions with the ERC and gas company officials we have agreed to use the new 1998 asset valuation and to treat depreciation at a 3 33% rate This assumes that all the assets have a remaining life of 30 years, which is patently incorrect Still, the agreement is to use the estimated but otherwise reasonable asset base as one asset type, and from here on to depreciate each new piece of capital equipment in accordance with its own depreciation schedule Schedule C-2 introduces a significant change in depreciation which on this and on subsequent Schedules will be based on the agreed-upon 1998 asset value

The change in asset valuation and its new depreciation treatment significantly raise depreciation from 177 million drams to 3 97 billion drams (Line 24) Given the full cost-recovery methodology inherent in Schedule C-2 the overall tariff to the end-user rises from $79 15 per MCM under the old depreciation treatment to $84 90 under the new treatment, for an increase of 7 3% (Line 75)

Given the inconsistent treatment of profits under the original scenario, Schedule ERC, where profits were 8 0% of costs for Transgas and 10 5 % for Haygas, compared to an undefined mark-up for Armgasprom depending on whether long-term interests were included in profits or not, we chose to keep profits unchanged in Schedules ERC-2 through D-2 including this Schedule C-2 Accordingly the rates of return of the component companies did not change in moving from Schedule B-2 to C-2 However the depreciation accrual rate did change to the newly-defined 3 33% level

While the rate of return remained the same from Schedule B-2 to C-2 the cash flow to the component companies, and with it their claim to intra-Armenia funds rose significantly The State's share of total claims declined from 71 7% to 59 9% (Line 92), making room for an increase in company claims from 28 3% to 40 1% (Line 93) This is a significant but still insufficient improvement

Schedule D-2: Introducing a Bad Debt Reserve

There is one problem we did not address in sufficient detail the perennial collection problem besetting all energy forms in Armenia, including natural gas We believe that collection is feasible at percentage rates comparable to those in the West, if Western measures are used in collecting bad debts The Energy Law now permits the cutting off of natural gas deliveries to recalcitrant consumers but the physical connections are such that this can only be done after an appropriate re-design of the gas delivery lines, including the installation of valves and meters

In the meantime, non-collection continues to be a problem In Schedule D-2 we set up a bad-debt reserve of 5% principally for demonstration purposes How significant and potentially devastating bad debts are on the natural gas delivery system in Armenia can be gleaned from the fact that this relatively modest reserve of 5% represents two thirds of total operating expenses (Lines 16 and 19) The establishment of this reserve raises overall tariffs from $84 90 per MCM in Schedule C-2 to $90 32 here (Line 75)

Given the underlying assumptions of Schedule D-2 the establishment of a bad-debt reserve does not of course affect the component companies' rates of return or depreciation accrual rates As assumed in Schedule D-2 the establishment of a bad-debt reserve simply raises operating costs for a net increase of the companies' claim on funds generated within Armenia from 40 1% to 47 4% with a concomitant reduction in claims held by the State We believe that the remedy to insufficient collections rests with proper enforcement rather than with the inclusion of costs related to bad-debts which would increase the tariff burden on those end-users who pay their gas bills regularly

Schedule E-2: Introducing Asset-Based Rates of Return

Of all the suggested changes, perhaps the most significant and methodologically the most important is the switch from using mark-ups on costs to returns on assets for the establishment of profits This change was introduced in Schedule E-2 where we used a 15% rate of return the same rate as that recommended by the World Bank for oil and gas field rehabilitation operations in Russia i e without the additional geological exploration risk This rate is deemed sufficient to attract interested foreign investors The important point is that under such a regime lenders can see that earnings are available from existing operations to pay off the principal and interest requirements on new loans

The results of this switch are startling To begin with, the rates of return by definition rise to the target level of 15% These rates also raise taxes very significantly, from 24 8 billion drams before to 45 9 billion drams after the establishment of asset-based rates of return (Line 78 in Schedule C-2 and Line 82 in Schedule E-2) Since taxes are part of the costs incurred by the operators they are reflected in the tariffs as are the increased returns, for an overall increase in tariffs from $84 90 per MCM (Line 75 Schedule C-2, no bad-debt reserve) to $120 47 an increase of 42% Surprisingly the State's overall claim on intra-Armenian funds rises from 59 9% (Schedule C-2) to 82 8% That again is a reflection of the fact that the component companies' shareholder is the State whose return has been raised in this new scenario This is, of course, an untenable situation, but the remedy does not lie in mandatory allocations of the shareholders' returns as practiced now Instead and viewed from the Western perspective the excessive State claim on intra-Armenian funds would suggest a re-thinking of the tax regime

Schedule F-2: Cost Adjustments Based on US Gas Company Norms

With one exception, Schedule E-2 completes the conversion from the original ERC-suggested tariff methodology to a Western approach That exception is the fact that the natural gas companies in Armenia appear to be operating at a unit cost significantly lower than Western gas companies Schedule F-2 addresses the issue of operating cost differentials It answers the question of how tariffs and other gas company parameters would be affected if Western unit costs were imputed to the Armenian natural gas tariffs, given the organizational structure and tax regime as they now exist in Armenia

Schedule F-2 then, is in all respects the same as its predecessor It contains all the adjustments discussed earlier, except for the bad-debt reserve In particular Schedule F-2 classifies interest on long-term debt as a cost, it applies property taxes and depreciation to the 1998 asset valuation and it uses a 15% rate of return on assets As mentioned, the one change from the predecessor Schedule is the adjustment of operating costs to US standards Schedule F-2 is the final adjustment in this series and it will be the basis for discussion for further adjustments to (a) bring the operating costs back down in those areas where they are patently unrealistic as applied to Armenia and (b) provide additional permanent or transitional adjustments to make the tariff acceptable to the various parties involved not the least of which would be the consuming public

The adjustments to US cost standards are shown for each component company on Line 25 of Schedule F-2 The derivation of these adjustment figures is explained in detail in Appendix B In absolute terms, the adjustment for US operating costs nearly triples administrative expenses (Armgasprom) it raises pipeline operating costs by some 60 percent, and it almost exactly triples operating expenses of Haygas Suffice it here to point out that these adjustments are substantial in absolute terms, but that their impact on tariffs is far less significant than one might have guessed

The average delivered pnce of natural gas to all consumers with this last cost adjustment nses from $120 47 per MCM to $128 10 an increase of 6 3% (Line 78) This increase in tariffs is small compared to the percentage increase in operating costs of the component companies mostly because in the overall cost and rate structure operating costs do not loom large Since under a Western cost recovery system we start with a target rate of return that rate remains unchanged at 15% However, a significant improvement is achieved in terms of intra-Armenian funds generated in the natural gas industry and allocated to operating costs These funds nse from 17 2% to 24 4% Lines 100 in Schedules E-2 and F-2

Summary of Results

Tariffs and Delivered Prices

When it comes to tariffs and delivered natural gas pnces, two questions come to mind The first is how the different Schedules ERC through F-2 in their progress to total adaptation to Western standards affect tariffs and pnces in Armenia and the second question is how these Armenian tariffs and pnces compare to those in the West Tables 3-A and 3-B deal with both of these questions

As can be seen in Table 3-A, the average delivered pnce of natural gas nses by 63%, from $78 60 per MCM in the ERC Schedule to $128 10 in the final Schedule F-2 This compares with the current Armenian tariff of $79 10 for large consumers and $102 00 for residential consumers On the face of it a 63% increase from generally depressed gas pnces does not appear to be excessive if that is what it takes to restore the system to long-term viability

We will eventually deal with the issue of whether efforts to reduce tariffs from the Schedule F-2 level are desirable and, if so, how such a reduction can be achieved A review of Table 3-A sheds some light on the question of where such corrections might be successful For example the first three excursions from Schedule ERC do not significantly affect average delivered pnces of natural gas and in any event, two of these three adjustments are irreversible if a conversion to Western regulatory standards is desired In short moving interest on long-term debt into O&M costs, and imposing property taxes at the current rate of 0 6% on assets, based on either the old or the 1998 valuation does not affect the tariff a great deal These moves would be ineffective as regards tariff adjustments and should therefore be left out of a possible list of policy options

Schedule C-2 shows the first significant impact on tariffs and delivered pnces Here the application of a Western-type depreciation regime to the 1998 asset base raises the average delivered pnce from $79 15 per MCM to $84 90, or 6 3% The new burden imposed by Schedule C-2 is the result of two factors the depreciation rate and the asset base to which it is applied We have used the lowest possible depreciation rate of 3 3%, assuming a remaining life of 30 years for all of the equipment currently in use a simplifying but patently unrealistic assumption that is defensible only on the grounds that the valuation itself of these assets is uncertain As mentioned earlier the funds generated by the depreciation account are urgently needed to facilitate the repayment of loans that must be secured to replace and improve deteriorating facilities To reduce the depreciation rate further will strain the credibility of the policy maker and will discourage foreign investors otherwise willing to buy into the system at the suggested rate

However, rather than dealing with changing depreciation rates, the asset base itself can be adjusted We do not propose here that we or others unilaterally suggest changes from a carefully derived and widely accepted asset value, but we do suggest that part of the natural gas assets, particularly those of Transgas which are currently used at 20% of capacity may be mothballed Such a move would keep the assets on the books at the suggested value, but the mothballed portion of these assets could be moved out of the rate base into a special asset category entitled "Gas Plant Held For Future Use" to be moved back into the rate base if and when the system s capacity utilization rises We will raise this topic again in Chapter 3

We will leave out the issue of a bad-debt reserve except to point out that Schedule D-2 was introduced primarily for the purpose of showing how dramatically the relatively small bad-debt reserve of 5 0% affects tariffs and delivered prices In our discussion of Schedule D-2 we mentioned that the remedy for bad debts does not lie in establishing reserves which simply imply a subsidization from those who pay their bills to those who do not at higher rates

A very significant increase in average delivered prices results from the introduction of a 15% rate of return on the asset base Because of that increase the rate of return on assets is obviously a tempting economic and policy target We will have more to say about this issue in Chapter 3

The move towards US cost standards Schedule F-2 raises the average delivered price of natural gas but not significantly We might point out here for elaboration in Appendix B that the cost adjustment was not a straight pass-through based on relevant parameters the most important of which is the asset base We did make a sensible concession, using Armenia's current book value after depreciation in relation to US original investments With that concession the overall rate increase was only $7 63 per MCM, or 6 3% Whatever one might say about the appropriateness of this adjustment its impact on tariffs is relatively minor, and the cash flow generated through its use all accrues to the component companies which badly need the infusion We would suggest that reductions from US cost standards be approached with caution, and that additional rate reductions if needed can and should be achieved through other policy options

Finally not visible in the Schedules listed in Table 3-A is the fact that the seemingly high tariffs are the result of a notorious under-utilization of capital in a highly capital-intensive industry A more efficient utilization of the capital equipment will reduce tariffs One way of achieving this has already been mentioned the reduction of the capital equipment in use through mothballing Another avenue is the increase in volumes shipped through the system We will eventually run cases on our model that will reflect the impact on tariffs as a result of increased gas volumes which will become inevitable when shipments to residential consumers are resumed For example, doubling the import volumes will nearly cut in half the incremental tariffs of Armgasprom and Transgas

Comparative Natural Gas Prices

Table 3-B is a comparison of US versus Armenian natural gas prices At this stage we are unable to comment on delivered prices by class of customers in Armenia The allocation procedure between consumer classes and its application to Armenia is the topic of Chapter 3 We can, however, comment on the reasonableness of the suggested tariff methodology in terms of overall costs

Since Armenia does not produce natural gas of its own, we assumed that the price paid at the Armenian border for gas imports at the start of this report inclusive of the VAT is the equivalent of the US wellhead price That price is $76 63 per MCM compared to the early 1998 Armenian import price (again including the VAT) of $66 00 That in itself raises a disturbing question which we will not get into here is the import price in Armenia tenable in the long run and what will happen if it goes up?

In any event, by the time gas is delivered at the city gate in the US, it is raised by $38 85 per MCM (from $115 48-76 63) In Armenia that increase is a mere $8 63 per MCM in the ERC base case, and it would be $40 41 if Schedule F-2 prevailed without further adjustments The listed Armenian Schedule F-2 city gate price of $106 41 per MCM is the sum of the import price ($66 00) plus the incremental Armgasprom and Transgas tariffs of $4 57 and $35 84 Is this reasonable? We do not know the average length of transport of natural gas in the United States but we suspect that it is considerably larger than in Armenia On the other hand the US prices reflect costs at or near capacity versus a pipeline capacity utilization of some 20% in Armenia In addition pipeline losses in the US run below 1 0%, compared to losses of 3 0% in Armenia not counting gas used for internal consumption Hence Armenia's relatively high city gate delivery price in Schedule F-2 is realistic Reducing losses and increasing capacity utilization through mothballing or increased shipments or both will go a long way in bringing that price down to acceptable levels

In the delivery of natural gas from the city gate to the end-user Armenia's incremental tariff of $21 69 per MCM ($128 10-$106 41) is favorable when compared to the US incremental tariff of $39 83 even in the most expensive F-2 case In the ERC base case by contrast the incremental tariff is visibly underpriced by a factor of 10, relative to the equivalent US tariff, Table 3-B However it should be noted that the US tariff is somewhat understated since it includes direct deliveries at prices below city gate prices to electric utilities for some 14% of all gas deliveries In addition, industrial deliveries (44 3% of all gas deliveries to end-users) are in a similar position The fact that the average US industrial tariff of $120 78 per MCM is only $5 22 above the city gate price suggests that substantial portions of industrial gas deliveries take place directly from transmission lines This is a vivid demonstration of the efficiency of third-party contracts where the consumer with or without intermediation by the distribution company contracts directly with suppliers for gas purchases and with the pipeline for transmission Not surprisingly, residential distribution is the most expensive activity The average price of natural gas delivered in the US residential sector is $223 more than double the current price in Armenia, for an average incremental tariff from the city gate of $108 41 per MCM This will be discussed in more detail in Chapter 3

Claims on Natural Gas Industry Funds

Tables 4-A and 4-B show how the total gas industry funds are split between amounts going abroad and amounts remaining in the country As regards actual cash generation perhaps of greatest interest are the last four Columns of Table 4-A which show how the funds remaining in Armenia are shared among the principal Armenian claimants the gas companies, the State via taxes, and the shareholders which are at present the State

As regards funds going abroad, given the import price of natural gas in early 1998 of $55 00 per MCM and the assumed import volume of 1 672 BCM per year, the importer gets $91 99 million per year for all policy scenarios Schedules ERC through F-2 The funds generated and remaining in Armenia are sensitive to the stipulated policy scenarios Under the original Energy Regulatory Commission design Schedule ERC, the funds remaining in Armenia total $32 34 million That amount is shared as follows The gas companies get $7 79 million (or 24 1%, Table 4-B), the State as a collector of taxes gets $22 28 million (or 68 9%, Table B-4), and the shareholders get $2 27 million (or 7 0%) Since the State is at present the only shareholder, the State's total take from intra-Armenian funds is $24 55 million or 75 9% of the total (the last Column of Tables 4-A and 4-B)

In moving from the original ERC Schedule to the final Western model of Schedule F-2, the total funds generated and remaining in Armenia are roughly tripled, from $32 3 million per year to $110 7 million The companies' take is more than tripled rising from $7 79 million to $27 02 million while taxes go up by a factor of 2 15 from $22 3 million per year to $47 9 million This points up the difference between the US style income tax (tax on profits) and the VAT as used in Europe and Armenia The income tax would not impose taxes on additional costs incurred in bringing the pipeline system up to international standards while the VAT will

The shareholders' take in the ERC case, Tables 4-A and 4-B, is misleading since interest on long-term debt is included in profits When the interest is removed from profits as it is without off-setting compensation in Schedules ERC-2 through D-2 it becomes quite clear that there is no way to attract foreign capital under the existing tax and profit regime The shareholders receive approximately half a million dollars or between 1 0 and 2 0 percent of the total funds under these scenarios However the shareholders take rises to $35 7 million per year (36.2% of total take) as soon as the concept of a return on assets 15% in the case at hand is introduced in Schedule E-2

For better or for worse given the fact that the State is the only shareholder at present the effect of raising profits by relating them to the asset base is to raise the State's overall share In Schedule F-2 the State's total claim including profits rises from $24 55 million per year to $83 63 million In terms of the State's percentage claims on total funds as a tax collector and as a shareholder these remain almost unchanged at close to 76% for both the ERC and the Western cases but on a base triple the size in Schedule F-2

This discussion raises the question of when a tax regime becomes burdensome In the discussion that follows we will focus on the State's take through taxation since the return to shareholders needs to remain at or near 15% regardless of the ownership status If the natural gas industry is to attract foreign equity capital, that need is obvious If the State remains the owner of the industry the investment of capital funds still has to be undertaken in accordance with the capital's prospective rate of return, unless (as in the past) the Government chooses to ignore market signals to its own detriment A policy of investment regardless of returns leads to massive misallocations of resources and to economic inefficiencies that will become a heavy burden on the economy at large and on the people who live in it

Rate of Return on Assets

We have focused our discussion on Return on Assets even though in regulatory practice the rate base consists of assets plus working capital We did not have usable balance sheets for the three component companies and, in any event, their working capital is sure to be negligible compared with their asset base, given their limited operating budget If so, the effect on tariffs through the inclusion of working capital is bound to be small Still, if the emphasis is on emulating Western regulatory practices the component companies need to shift their accounting practices to international standards which will include a definition of, and accounting for, working balances

We should also point out that the three companies have essentially no long-term debt Hence the return to rate base and to common equity is the same If this were not so or if at some point in the future equity investment is leveraged by substantial long-term debt (a 70% debt/equity ratio is not uncommon for utilities and pipelines in the United States), the return on rate base will be the weighted average cost of borrowed capital plus the return on common equity For Armenia, our recommended return on common equity is 15% In the US, where conditions are favorable to investments because of long-term stability and low risks the return on common equity is closer to 12 0% and long-term loans run at 8 0% or less Thus on a 50/50 leveraged investment, the return on rate base would be 0 5*12 0 + 0 5*8 0, or 10 0%

The returns on assets for the three Armenian gas companies are shown under the different scenarios, Schedules ERC through F-2 in the last Column of Table 5 That Table also lists other data that are reproduced from earlier tables for convenience

As Table 5 shows, the Base Case Schedule ERC exhibits the highest overall return on assets for the lowest funds flow, at 28 4% This seemingly contradictory behavior is caused by two factors that have been corrected on the way to the final Schedule F-2 First, the profits to the three gas companies include interest on long-term debt and second, the rate base is the extremely low pre-1998 asset valuation The first move toward a Western regulatory scenario was the reclassification of long-term debt as a cost and its removal from profits That reduced the return on assets to a low 6 9% The second significant change in the return on assets occurred in Schedule B-2 where the asset base was increased from its extremely low value of $8 0 million to the more realistic value of $238 million That brought the return on assets down to 0.23%, a hopelessly low level that would inhibit any foreign or

Armenian investment By contrast the 15% rate of return on assets of Schedules E-2 and F-2 are at design level

NATURAL GAS ENTERPRISES
ARMROSGASPROM PLAN
For the 12-Month Period Ending June 30 1999
BASE CASE USING ENERGY REGULATORY COMMISSION DATA AND METHODOLOGY

	REVENUE REQUIREMENTS	ARMROS GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL
		THOUSANDS OF ARMENIAN DRAMS			
1	**OPERATING EXPENSES**				
2	MATERIALS AND RAW MATERIALS	10 000	100 000	20 000	130 000
3	SALARY FUND	100 000	221 000	400 000	721 000
4	ELECTRICITY CONSUMPTION	18 000	96 000	22 000	136 000
5	FUEL CONSUMPTION	20 000	74 000	45 000	139 000
6	TECHNOLOGICAL LOSSES	0	0	0	0
7	PERSONNEL TRAINING	1 000	3 800	5 000	9 800
8	TRAVEL EXPENSES	28 000	10 000	3 400	41 400
9	RENT	1 000	0	10 000	11 000
10	CATHODIC PROTECTION	0	7 400	22 600	30 000
11	TELEPHONE CHARGES	34 000	8 000	10 000	52 000
12	COMMUNAL UTILITIES CHARGES	4 000	10 000	6 000	20 000
13	AUDIT SERVICES	20 000	9 000	17 000	46 000
14	BANKING SERVICES	332 000	6 000	11 000	349 000
15	MARKETING SERVICES	50 000	0	0	50 000
16	BAD DEBTS	0	0	0	0
17	PROTECTION FROM NATURAL CALAMITY	3 000	46 000	33 000	82 000
18	OTHER EXPENDITURES	22 000	12 000	14 700	48 700
19	**TOTAL OPERATING EXPENSES**	**643 000**	**603 200**	**619 700**	**1 865 900**
20	**MAINTENANCE EXPENSES**				
21	VEHICLE REPAIRS AND MAINTENANCE	8 000	20 000	12 000	40 000
22	REPAIR FUND	100 000	835 428	777 018	1 712 446
23	**TOTAL MAINTENANCE EXPENSES**	**108 000**	**855 428**	**789 018**	**1 752 446**
24	**DEPRECIATION (Used 4 425 % on Gov Appraised Value)**	**8 000**	**119 000**	**50 000**	**177 000**
25	**TAXES OTHER THAN PROFIT TAXES**				
26	CUSTOMS FEES	140 000	0	0	140 000
27	PROPERTY TAX (Used 0 6% on Gov Appraised Value)	0	0	0	0
28	SOCIAL TAXES (Cap at 11 584/Employee/Month)	36 000	79 560	144 000	259 560
29	TOTAL OTHER TAXES	176 000	79 560	144 000	399 560
30	**INTEREST ON SHORT TERM LOANS**	**100 000**	**0**	**0**	**100 000**
31	**TOTAL OPERATING COSTS**	**1 035 000**	**1 657 188**	**1 602 718**	**4 294 906**
41	CURRENT ASSET VALUE Millions of Drams Old Armenian Standard	19	2 768	1 213	4 000

Note Light Frames on Lines Denote Payments to or Collections by State

NATURAL GAS ENTERPRISES
ARMROSGASPROM PLAN
For the 12-Month Period Ending June 30 1999
BASE CASE USING ENERGY REGULATORY COMMISSION DATA AND METHODOLOGY

		ARMROS GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL
		THOUSANDS OF ARMENIAN DRAMS			
50	Volume Received 1000 Standard Cubic Meters	1 672 500	1 672 500	1 608 945	1 672 500
51	Losses %	0	3 80%	1 68%	5 48%
52	Volume Delivered - 1000 Standard Cubic Meters	1 672 500	1 608 945	1 581 915	1 581 915
53	Price Charged by Importer $/MCM	55 00			
54	Amount Payable to Importer $ Millions	91 988			
55	VAT %	20%			
56	Amount Payable to State Due to VAT $ Millions	18 3975			
57	Total Amount Import Costs plus VAT $ Million	110 385			
58	Equivalent Tariff upon Receipt of Gas $/MCM	66 000	69.229	74 633	78 595
59	TOTAL OPERATING COSTS (From Preceding Page)	1 035 000	1 657 188	1 602 718	4 294 906
60	Profit Before Profit Tax (incl Interest on Long-Term Debt) Thousands of Drams	1,215 000	132 574	168,282	1 515 856
61	Total Operating Cost + Profit Before Profit Tax Subject to VAT 10^3 Drams	2 250 000	1 789 762	1 771 000	5 810 762
62	Total Amount After VAT and Profit Tax (Total Additional Revenue Requirement)	2 700 000	2 147 714	2 125 200	6 972 914
63	VAT on Company Operations Thousands of Drams	450 000	357 952	354 200	1 162 152
64	Profit Tax Rate %	25 0%	25 0%	25 0%	
65	Tax on Profits Thousands of Drams	303 750	33 144	42 071	378 964
66	After-Tax Profits (Incl Interest on Long Term Debt) Thousands of Drams	911 250	99 431	126,212	1 136 892
		MILLIONS OF DOLLARS			
67	Total Operating Costs $ Millions	2 070	3 314	3 205	8 590
68	Profit Before Profit Tax (including Interest on Long Term Debt) $ Millions	2 430	0.265	0 337	3 032
69	Total Operating Cost + Profit Before Profit Tax Subject to VAT $ Millions	4 500	3 580	3 542	11 622
70	Total Amount After VAT and Profit Tax (Total Additional Revenue Requirement)	5 400	4 295	4 250	13 946
71	VAT on Company Operations $ Millions	0 900	0 716	0 708	2 324
72	Tax on Profits $ Millions	0 608	0 066	0 084	0 758
73	After Tax Profits (incl Interest on Long Term Debt) $ Millions	1 823	0 199	0 252	2 274
74	Total Invoice $ Millions	115 785	120 080	124 331	124 331
75	Overall Tariff $/MCM	69 229	74 633	78 595	78 595
76	Incremental Tariff $/MCM	3 229	5 404	3 962	12 595
		CLAIMS ON NATURAL GAS EXPENDITURES			
	Total Claims $ Millions				
77	Amount Payable to Importer	91 988	0 000	0 000	91 988
78	Claims by State Including Other Taxes	20 257	0 941	1 081	22 279
79	Operating Costs Excluding Other Taxes	1 718	3 155	2 917	7 791
80	Claims by Shareholders (After Tax Profits Includes $ Interest on L T Debt)	1 823	0 199	0 252	2 274
81	Total Charges	115 785	4 295	4 250	124 331
82	Armenian Charges	23 798	4 295	4 250	32 343
	Claims % of Total Costs				
83	Amount Payable to Importer	79 4%	0 0%	0 0%	74 0%
84	Claims by State	17 5%	21 9%	25 4%	17 9%
85	Operating Costs	1 5%	73 5%	68 6%	6 3%
86	Claims by Shareholders (After Tax Profits Includes $ Interest on L T Debt)	1 6%	4 6%	5 9%	1 8%
87	Total Claims	100 0%	100 0%	100 0%	100 0%
	Claims % of Costs Added in Armenia				
88	Claims by State	85 1%	21 9%	25 4%	68 9%
89	Operating Costs	7 2%	73 5%	68 6%	24 1%
90	Claims by Shareholders (After Tax Profits Includes $ Interest on L T Debt)	7 7%	4 6%	5 9%	7 0%
91	Total Claims	100 0%	100 0%	100 0%	100 0%
	Claims % of Costs Added in Armenia with State as Only Shareholder				
92	Claims by State	92 8%	26 5%	31 4%	75 9%
93	Operating Costs	7 2%	73 5%	68 6%	24 1%
94	Total Claims	100 0%	100 0%	100 0%	100 0%
95	Rate of Return	4796 05%	3 59%	10 40%	28 42%
96	Depreciation Accrual Rate	42 11%	4 30%	4 12%	4 43%

Note Light Frames on Lines Denote Payments to or Collections by State

NATURAL GAS ENTERPRISES
ARMROSGASPROM PLAN
For the 12-Month Period Ending June 30 1999
CHANGE FROM BASE CASE INTEREST ON L T DEBT MOVED INTO O&M COSTS

	REVENUE REQUIREMENTS	ARMROS GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL
		THOUSANDS OF ARMENIAN DRAMS			
1	**OPERATING EXPENSES**				
2	MATERIALS AND RAW MATERIALS	10 000	100 000	20 000	130 000
3	SALARY FUND	100 000	221 000	400 000	721 000
4	ELECTRICITY CONSUMPTION	18 000	96 000	22 000	136 000
5	FUEL CONSUMPTION	20 000	74 000	45 000	139 000
6	TECHNOLOGICAL LOSSES	0	0	0	0
7	PERSONNEL TRAINING	1 000	3 800	5 000	9 800
8	TRAVEL EXPENSES	28 000	10 000	3 400	41 400
9	RENT	1 000	0	10 000	11 000
10	CATHODIC PROTECTION	0	7 400	22 600	30 000
11	TELEPHONE CHARGES	34 000	8 000	10 000	52 000
12	COMMUNAL UTILITIES CHARGES	4 000	10 000	6 000	20 000
13	AUDIT SERVICES	20 000	9 000	17 000	46 000
14	BANKING SERVICES	332 000	6 000	11 000	349 000
15	MARKETING SERVICES	50 000	0	0	50 000
16	BAD DEBTS	0	0	0	0
17	PROTECTION FROM NATURAL CALAMITY	3 000	46 000	33 000	82 000
18	OTHER EXPENDITURES	22 000	12 000	14 700	48 700
19	**TOTAL OPERATING EXPENSES**	**643 000**	**603 200**	**619 700**	**1 865 900**
20	**MAINTENANCE EXPENSES**				
21	VEHICLE REPAIRS AND MAINTENANCE	8 000	20 000	12 000	40 000
22	REPAIR FUND	100 000	835 428	777 018	1 712 446
23	**TOTAL MAINTENANCE EXPENSES**	**108 000**	**855 428**	**789 018**	**1 752 446**
24	**DEPRECIATION (Used 4.425 % on Gov Appraised Value)**	**8 000**	**119 000**	**50 000**	**177 000**
25	**TAXES OTHER THAN PROFIT TAXES**				
26	CUSTOMS FEES	140 000	0	0	140 000
27	PROPERTY TAX (Used 0 6% on Gov Appraised Value)	0	0	0	0
28	SOCIAL TAXES (Cap at 11 584/Employee/Month)	36 000	79 560	144 000	259 560
29	TOTAL OTHER TAXES	176 000	79 560	144 000	399 560
30	**INTEREST ON SHORT TERM LOANS**	**100 000**	**0**	**0**	**100 000**
31	INTEREST ON LONG TERM DEBT	800 000	0	0	800 000
32	TOTAL OPERATING COSTS	1 835 000	1 657 188	1 602 718	5 094 906
33	CURRENT ASSET VALUE Millions of Drams Old Armenian Standard	19	2 768	1 213	4 000

Note Light Frames on Lines Denote Payments to or Collections by State
Heavy Frames on Lines Denote Changes from Schedule ERC

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NATURAL GAS ENTERPRISES

ARMROSGASPROM PLAN

For the 12-Month Period Ending June 30 1999

CHANGE FROM BASE CASE INTEREST ON L T-DEBT MOVED INTO O&M COSTS

		ARMROS GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL
		THOUSANDS OF ARMENIAN DRAMS			
50	Volume Received 1000 Standard Cubic Meters	1 672 500	1 672 500	1 608 945	1 672 500
51	Losses %	0	3 80%	1 68%	5 48%
52	Volume Delivered 1000 Standard Cubic Meters	1 672 500	1 608 945	1 581 915	1 581 915
53	Price Charged by Importer $/MCM	55 00			
54	Amount Payable to Importer $ Millions	91 988			
55	VAT %	20%			
56	Amount Payable to State Due to VAT $ Millions	18 3975			
57	Total Amount Import Costs plus VAT $ Million	110 385			
58	Equivalent Tariff upon Receipt of Gas $/MCM	66 000	68 730	74 114	78 068
59	TOTAL OPERATING COSTS (From Preceding Page)	1 835 000	1 657 188	1 602 718	5 094 906
60	After Tax Profit (No Interest on Long Term Debt) Thousands of Drams	50 500	99 431	126 212	276 142
61	Profit Before Profit Tax (No Interest on Long Term Debt) Thousands of Drams	67 333	132 574	168 282	368 189
62	Total Operating Cost + Profit Before Profit Tax Subject to VAT 10^3 Drams	1 902 333	1 789 762	1 771 000	5 463 095
63	Total Amount After VAT and Profit Tax (Total Additional Revenue Requirement)	2 282 800	2 147 714	2 125 200	6 555 714
64	VAT on Company Operations Thousands of Drams	380 467	357 952	354 200	1 092 619
65	Profit Tax Rate %	25 0%	25 0%	25 0%	
66	Tax on Profits Thousands of Drams	16 833	33 144	42 071	92 047
		MILLIONS OF DOLLARS			
67	Total Operating Costs $ Millions	3 670	3 314	3 205	10 190
68	After Tax Profit (No Interest on Long Term Debt) $ Millions	0 101	0 199	0 252	0 552
69	Profit Before Profit Tax (No Interest on Long Term Debt) Thousands of Drams	0 135	0 265	0 337	0 736
70	Total Operating Cost + Profit Before Profit Tax Subject to VAT $ Millions	3 805	3 580	3 542	10 926
71	Total Amount After VAT and Profit Tax (Total Additional Revenue Requirement)	4 566	4 295	4 250	13 111
72	VAT on Company Operations $ Millions	0 761	0 716	0 708	2 185
73	Tax on Profits $ Millions	0 034	0 066	0 084	0 184
74	Total Invoice $ Millions	114 951	119 246	123 496	123 496
75	Overall Tariff $/MCM	68 730	74 114	78 068	78 068
76	Incremental Tariff $/MCM	2 730	5 385	3 953	12 068
		CLAIMS ON NATURAL GAS EXPENDITURES			
	Total Claims $ Millions				
77	Amount Payable to Importer	91 988	0 000	0 000	91 988
78	Claims by State Including Other Taxes	19 544	0 941	1 081	21 566
79	Operating Costs Excluding Other Taxes	3 318	3 155	2 917	9 391
80	Claims by Shareholders (After Tax Profits No Interest on L T Debt)	0 101	0 199	0 252	0 552
81	Total Charges	114 951	4 295	4 250	123 496
82	Armenian Charges	22 963	4 295	4 250	31 509
	Claims % of Total Costs				
83	Amount Payable to Importer	80 0%	0 0%	0 0%	74 5%
84	Claims by State	17 0%	21 9%	25 4%	17 5%
85	Operating Costs	2 9%	73 5%	68 6%	7 6%
86	Claims by Shareholders (After Tax Profits No Interest on L T Debt)	0 1%	4 6%	5 9%	0 4%
87	Total Claims	100 0%	100 0%	100 0%	100 0%
	Claims % of Costs Added in Armenia				
88	Claims by State	85 1%	21 9%	25 4%	68 4%
89	Operating Costs	14 4%	73 5%	68 6%	29 8%
90	Claims by Shareholders (After Tax Profits No Interest on L T Debt)	0 4%	4 6%	5 9%	1 8%
91	Total Claims	100 0%	100 0%	100 0%	100 0%
	Claims % of Costs Added in Armenia with State as Only Shareholder				
92	Claims by State	85 6%	26 5%	31 4%	70 2%
93	Operating Costs	14 4%	73 5%	68 6%	29 8%
94	Total Claims	100 0%	100 0%	100 0%	100 0%
95	Rate of Return	265 79%	3 59%	10 40%	6 90%
96	Depreciation Accrual Rate	42 11%	4 30%	4 12%	4 43%

Note Light Frames on Lines Denote Payments to or Collections by State
Heavy Frames on Lines Denote Changes from Schedule ERC

NATURAL GAS ENTERPRISES
ARMROSGASPROm PLAN
For the 12-Month Period Ending June 30 1999
CHANGE FROM BASE CASE (1) INTEREST ON L T DEBT MOVED INTO O&M COSTS (2) ADD PROPERTY TAX OLD VALUATION

	REVENUE REQUIREMENTS	ARMROS GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL
		THOUSANDS OF ARMENIAN DRAMS			
1	**OPERATING EXPENSES**				
2	MATERIALS AND RAW MATERIALS	10 000	100 000	20 000	130 000
3	SALARY FUND	100 000	221 000	400 000	721 000
4	ELECTRICITY CONSUMPTION	18 000	96 000	22 000	136 000
5	FUEL CONSUMPTION	20 000	74 000	45 000	139 000
6	TECHNOLOGICAL LOSSES	0	0	0	0
7	PERSONNEL TRAINING	1 000	3 800	5 000	9 800
8	TRAVEL EXPENSES	28 000	10 000	3 400	41 400
9	RENT	1 000	0	10 000	11 000
10	CATHODIC PROTECTION	0	7 400	22 600	30 000
11	TELEPHONE CHARGES	34 000	8 000	10 000	52 000
12	COMMUNAL UTILITIES CHARGES	4 000	10 000	6 000	20 000
13	AUDIT SERVICES	20 000	9 000	17 000	46 000
14	BANKING SERVICES	332 000	6 000	11 000	349 000
15	MARKETING SERVICES	50 000	0	0	50 000
16	BAD DEBTS	0	0	0	0
17	PROTECTION FROM NATURAL CALAMITY	3 000	46 000	33 000	82 000
18	OTHER EXPENDITURES	22 000	12 000	14 700	48 700
19	**TOTAL OPERATING EXPENSES**	**643 000**	**603 200**	**619 700**	**1 865 900**
20	**MAINTENANCE EXPENSES**				
21	VEHICLE REPAIRS AND MAINTENANCE	8 000	20 000	12 000	40 000
22	REPAIR FUND	100 000	835 428	777 018	1 712 446
23	**TOTAL MAINTENANCE EXPENSES**	**108 000**	**855 428**	**789 018**	**1 752 446**
24	**DEPRECIATION (Used 4.425 % on Gov Appraised Value)**	**8 000**	**119 000**	**50 000**	**177 000**
25	**TAXES OTHER THAN PROFIT TAXES**				
26	CUSTOMS FEES	140 000	0	0	140 000
27	PROPERTY TAX (Used 0 6% on Earlier Government Valuation)	114	16 608	7 278	24 000
28	SOCIAL TAXES (Cap at 11 584/Employee/Month)	36 000	79 560	144 000	259 560
29	**TOTAL OTHER TAXES**	**176 114**	**96 168**	**151 278**	**423 560**
30	**INTEREST ON SHORT TERM LOANS**	**100 000**	**0**	**0**	**100 000**
31	**INTEREST ON LONG TERM DEBT**	**800 000**	**0**	**0**	**800 000**
32	**TOTAL OPERATING COSTS**	**1 835 114**	**1 673 796**	**1 609 996**	**5 118 906**
33	**CURRENT ASSET VALUE Millions of Drams Old Armenian Standard**	19	2 768	1 213	4 000

Note Light Frames on Lines Denote Payments to or Collections by State
Heavy Frames on Lines Denote Changes from Schedule ERC-2

NATURAL GAS ENTERPRISES
ARMROSGASPROM PLAN
For the 12-Month Penod Ending June 30, 1999

CHANGE FROM BASE CASE (1) INTEREST ON L T-DEBT MOVED INTO O&M COSTS (2) ADD PROPERTY TAX OLD VALUATION

		ARMROS GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL
		THOUSANDS OF ARMENIAN DRAMS			
50	Volume Received 1000 Standard Cubic Meters	1 672 500	1 672 500	1 608 945	1 672 500
51	Losses %	0	3 80%	1 68%	5 48%
52	Volume Delivered 1000 Standard Cubic Meters	1 672 500	1 608 945	1 581 915	1 581 915
53	Price Charged by Importer $/MCM	55 00			
54	Amount Payable to Importer $ Millions	91 988			
55	VAT %	20%			
56	Amount Payable to State Due to VAT $ Millions	18 3975			
57	Total Amount Import Costs plus VAT $ Million	110 385			
58	Equivalent Tariff upon Receipt of Gas $/MCM	66 000	68 730	74 139	78 104
59	TOTAL OPERATING COSTS (From Preceding Page)	1 835 114	1 673 796	1 609 996	5 118 906
60	After Tax Profit (No Interest on Long Term Debt) Thousands of Drams	50 500	99 431	126 212	276 142
61	Profit Before Profit Tax (No Interest on Long Term Debt) Thousands of Drams	67 333	132 574	168 282	368 189
62	Total Operating Cost + Profit Before Profit Tax Subject to VAT 10^3 Drams	1 902 447	1 806 370	1 778 278	5 487 095
63	Total Amount After VAT and Profit Tax (Total Additional Revenue Requirement)	2,282 937	2 167 644	2 133 934	6 584 514
64	VAT on Company Operations Thousands of Drams	380 489	361 274	355 656	1 097 419
65	Profit Tax Rate %	25 0%	25 0%	25 0%	
66	Tax on Profits Thousands of Drams	16 833	33 144	42 071	92 047
		MILLIONS OF DOLLARS			
67	Total Operating Costs $ Millions	3 670	3 348	3.220	10.238
68	After Tax Profit (No Interest on Long Term Debt) $ Millions	0 101	0 199	0.252	0 552
69	Profit Before Profit Tax (No Interest on Long Term Debt) Thousands of Drams	0 135	0.265	0 337	0 736
70	Total Operating Cost + Profit Before Profit Tax Subject to VAT $ Millions	3 805	3 613	3 557	10 974
71	Total Amount After VAT and Profit Tax (Total Additional Revenue Requirement)	4 566	4 335	4 268	13 169
72	VAT on Company Operations $ Millions	0 761	0 723	0 711	2 195
73	Tax on Profits $ Millions	0 034	0 066	0 084	0 184
74	Total Invoice $ Millions	114 951	119 286	123 554	123 554
75	Overall Tariff $/MCM	68 730	74 139	78 104	78 104
76	Incremental Tariff $/MCM	2 730	5 409	3 965	12 104
		CLAIMS ON NATURAL GAS EXPENDITURES			
	Total Claims $ Millions				
77	Amount Payable to Importer	91 988	0 000	0 000	91 988
78	Claims by State Including Other Taxes	19 544	0 981	1 098	21 624
79	Operating Costs Excluding Other Taxes	3 318	3 155	2 917	9 391
80	Claims by Shareholders (After Tax Profits No Interest on L T Debt)	0 101	0 199	0 252	0 552
81	Total Charges	114 951	4 335	4 268	123 554
82	Armenian Charges	22 963	4 335	4 268	31 567
	Claims % of Total Costs				
83	Amount Payable to Importer	80 0%	0 0%	0 0%	74 5%
84	Claims by State	17 0%	22 6%	25 7%	17 5%
85	Operating Costs	2 9%	72 8%	68 4%	7 6%
86	Claims by Shareholders (After Tax Profits No Interest on L T Debt)	0 1%	4 6%	5 9%	0 4%
87	Total Claims	100 0%	100 0%	100 0%	100 0%
	Claims % of Costs Added in Armenia				
88	Claims by State	85 1%	22 6%	25 7%	68 5%
89	Operating Costs	14 4%	72 8%	68 4%	29 7%
90	Claims by Shareholders (After Tax Profits No Interest on L T Debt)	0 4%	4 6%	5 9%	1 7%
91	Total Claims	100 0%	100 0%	100 0%	100 0%
	Claims % of Costs Added in Armenia with State as Only Shareholder				
92	Claims by State	85 6%	27 2%	31 6%	70 3%
93	Operating Costs	14 4%	72 8%	68 4%	29 7%
94	Total Claims	100 0%	100 0%	100 0%	100 0%
95	Rate of Return	265 79%	3 59%	10 40%	6 90%
96	Depreciation Accrual Rate	42 11%	4 30%	4 12%	4 43%

Note Light Frames on Lines Denote Payments to or Collections by State
Heavy Frames on Lines Denote Changes from Schedule ERC 2

NATURAL GAS ENTERPRISES
ARMROSGASPROM PLAN
For the 12-Month Period Ending June 30 1999

CHANGE FROM BASE CASE (1) INTEREST ON L T DEBT MOVED INTO O&M COSTS (2) ADD PROPERTY TAX 1998 VALUATION

	REVENUE REQUIREMENTS	ARMROS GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL
		THOUSANDS OF ARMENIAN DRAMS			
1	**OPERATING EXPENSES**				
2	MATERIALS AND RAW MATERIALS	10 000	100 000	20 000	130 000
3	SALARY FUND	100 000	221 000	400 000	721 000
4	ELECTRICITY CONSUMPTION	18 000	96 000	22 000	136 000
5	FUEL CONSUMPTION	20 000	74 000	45 000	139 000
6	TECHNOLOGICAL LOSSES	0	0	0	0
7	PERSONNEL TRAINING	1 000	3 800	5 000	9 800
8	TRAVEL EXPENSES	28 000	10 000	3 400	41 400
9	RENT	1 000	0	10 000	11 000
10	CATHODIC PROTECTION	0	7 400	22 600	30 000
11	TELEPHONE CHARGES	34 000	8 000	10 000	52 000
12	COMMUNAL UTILITIES CHARGES	4 000	10 000	6 000	20 000
13	AUDIT SERVICES	20 000	9 000	17 000	46 000
14	BANKING SERVICES	332 000	6 000	11 000	349 000
15	MARKETING SERVICES	50 000	0	0	50 000
16	BAD DEBTS	0	0	0	0
17	PROTECTION FROM NATURAL CALAMITY	3 000	46 000	33 000	82 000
18	OTHER EXPENDITURES	22 000	12 000	14 700	48 700
19	**TOTAL OPERATING EXPENSES**	**643 000**	**603 200**	**619 700**	**1 865 900**
20	**MAINTENANCE EXPENSES**				
21	VEHICLE REPAIRS AND MAINTENANCE	8 000	20 000	12 000	40 000
22	REPAIR FUND	100 000	835 428	777 018	1 712 446
23	**TOTAL MAINTENANCE EXPENSES**	**108 000**	**855 428**	**789 018**	**1 752 446**
24	**DEPRECIATION (Used 4 425 % on Gov Appraised value)**	**8 000**	**119 000**	**50 000**	**177 000**
25	**TAXES OTHER THAN PROFIT TAXES**				
26	CUSTOMS FEES	140 000	0	0	140 000
27	PROPERTY TAX (Used 0 6% on 1998 Government Valuation)	3 366	494 370	216 690	714 426
28	SOCIAL TAXES (Cap at 11 584/Employee/Month)	36 000	79 560	144 000	259 560
29	TOTAL OTHER TAXES	179 366	573 930	360 690	1 113 986
30	**INTEREST ON SHORT TERM LOANS**	**100 000**	**0**	**0**	**100 000**
31	**INTEREST ON LONG TERM DEBT**	**800 000**	**0**	**0**	**800 000**
32	**TOTAL OPERATING COSTS**	**1 838 366**	**2 151 558**	**1 819 408**	**5 809 332**
33	**CURRENT ASSET VALUE Millions of Drams 1998 Valuation**	561	82 395	36 115	119 071
34	**CURRENT ASSET VALUE $ Millions 1998 Valuation**	1 12	164 79	72 23	238 14

Note Light Frames on Lines Denote Payments to or Collections by State
Heavy Frames on Lines Denote Changes from Schedule A-2

NATURAL GAS ENTERPRISES
ARMROSGASPROM PLAN
For the 12-Month Period Ending June 30 1999

CHANGE FROM BASE CASE (1) INTEREST ON L T DEBT MOVED INTO O&M COSTS (2) ADD PROPERTY TAX 1998 VALUATION

		ARMROS GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL
		THOUSANDS OF ARMENIAN DRAMS			
50	Volume Received 1000 Standard Cubic Meters	1 672 500	1 672 500	1 608 945	1 672 500
51	Losses %	0	3 80%	1 68%	5 48%
52	Volume Delivered 1000 Standard Cubic Meters	1 672 500	1 608 945	1 581 915	1 581 915
53	Price Charged by Importer $/MCM	55 00			
54	Amount Payable to Importer $ Millions	91 988			
55	VAT %	20%			
56	Amount Payable to State Due to VAT $ Millions	18 3975			
57	Total Amount, Import Costs plus VAT $ Million	110 385			
58	Equivalent Tariff upon Receipt of Gas $/MCM	66 000	68 735	74 857	79 152
59	TOTAL OPERATING COSTS (From Preceding Page)	1 838,366	2 151 558	1 819 408	5 809 332
60	After Tax Profit (No Interest on Long Term Debt) Thousands of Drams	50 500	99 431	126 212	276 142
61	Profit Before Profit Tax (No Interest on Long-Term Debt) Thousands of Drams	67 333	132 574	168 282	368 189
62	Total Operating Cost + Profit Before Profit Tax Subject to VAT 10^3 Drams	1 905 699	2 284 132	1 987 690	6 177 521
63	Total Amount After VAT and Profit Tax (Total Additional Revenue Requirement)	2,286 839	2 740 958	2 385 228	7 413 026
64	VAT on Company Operations Thousands of Drams	381 140	456 826	397 538	1 235 504
65	Profit Tax Rate %	25 0%	25 0%	25 0%	
66	Tax on Profits Thousands of Drams	16 833	33 144	42 071	92 047
		MILLIONS OF DOLLARS			
67	Total Operating Costs $ Millions	3 677	4 303	3 639	11 619
68	After-Tax Profit (No Interest on Long Term Debt) $ Millions	0 101	0 199	0 252	0 552
69	Profit Before Profit Tax (No Interest on Long Term Debt) Thousands of Drams	0 135	0.265	0 337	0 736
70	Total Operating Cost + Profit Before Profit Tax Subject to VAT $ Millions	3 811	4 568	3 975	12 355
71	Total Amount After VAT and Profit Tax (Total Additional Revenue Requirement)	4 574	5 482	4 770	14 826
72	VAT on Company Operations $ Millions	0 762	0 914	0 795	2 471
73	Tax on Profits $ Millions	0 034	0 066	0 084	0 184
74	Total Invoice $ Millions	114 959	120 441	125 211	125.211
75	Overall Tariff $/MCM	68 735	74 857	79 152	79 152
76	Incremental Tariff $/MCM	2 735	6 122	4 295	13 152
		CLAIMS ON NATURAL GAS EXPENDITURES			
	Total Claims $ Millions				
77	Amount Payable to Importer	91 988	0 000	0 000	91 988
78	Claims by State Including Other Taxes	19 552	2 128	1 601	23 281
79	Operating Costs Excluding Other Taxes	3 318	3 155	2 917	9 391
80	Claims by Shareholders (After-Tax Profits No Interest on L-T Debt)	0 101	0 199	0 252	0 552
81	Total Charges	114 959	5 482	4 770	125 211
82	Armenian Charges	22 971	5 482	4 770	33 224
	Claims % of Total Costs				
83	Amount Payable to Importer	80 0%	0 0%	0 0%	73 5%
84	Claims by State	17 0%	38 8%	33 6%	18 6%
85	Operating Costs	2 9%	57 6%	61 2%	7 5%
86	Claims by Shareholders (After Tax Profits No Interest on L T Debt)	0 1%	3 6%	5 3%	0 4%
87	Total Claims	100 0%	100 0%	100 0%	100 0%
	Claims % of Costs Added in Armenia				
88	Claims by State	85 1%	38 8%	33 6%	70 1%
89	Operating Costs	14 4%	57 6%	61 2%	28 3%
90	Claims by Shareholders (After Tax Profits No Interest on L T Debt)	0 4%	3 6%	5 3%	1 7%
91	Total Claims	100 0%	100 0%	100 0%	100 0%
	Claims % of Costs Added in Armenia with State as Only Shareholder				
92	Claims by State	85 6%	42 4%	38 8%	71 7%
93	Operating Costs	14 4%	57 6%	61 2%	28 3%
94	Total Claims	100 0%	100 0%	100 0%	100 0%
95	Rate of Return	9 00%	0 12%	0 35%	0 23%
96	Depreciation Accrual Rate	1 43%	0 14%	0 14%	0 15%

Note Light Frames on Lines Denote Payments to or Collections by State
Heavy Frames on Lines Denote Changes from Schedule A 2

NATURAL GAS ENTERPRISES
ARMROSGASPROM PLAN
For the 12-Month Period Ending June 30 1999

CHANGE BASE CASE (1) INTEREST ON L T DEBT IN O&M COSTS (2) ADD PROPERTY TAX 1998 VALUATION (3) ADD DEPRECIATION

	REVENUE REQUIREMENTS	ARMROS GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL
		THOUSANDS OF ARMENIAN DRAMS			
1	**OPERATING EXPENSES**				
2	MATERIALS AND RAW MATERIALS	10 000	100 000	20 000	130 000
3	SALARY FUND	100 000	221 000	400 000	721 000
4	ELECTRICITY CONSUMPTION	18 000	96 000	22 000	136 000
5	FUEL CONSUMPTION	20 000	74,000	45 000	139 000
6	TECHNOLOGICAL LOSSES	0	0	0	0
7	PERSONNEL TRAINING	1 000	3 800	5 000	9 800
8	TRAVEL EXPENSES	28 000	10 000	3 400	41 400
9	RENT	1 000	0	10 000	11 000
10	CATHODIC PROTECTION	0	7 400	22 600	30 000
11	TELEPHONE CHARGES	34 000	8 000	10 000	52 000
12	COMMUNAL UTILITIES CHARGES	4 000	10 000	6 000	20 000
13	AUDIT SERVICES	20 000	9 000	17 000	46 000
14	BANKING SERVICES	332 000	6 000	11 000	349 000
15	MARKETING SERVICES	50 000	0	0	50 000
16	BAD DEBTS	0	0	0	0
17	PROTECTION FROM NATURAL CALAMITY	3 000	46 000	33 000	82 000
18	OTHER EXPENDITURES	22 000	12 000	14 700	48 700
19	**TOTAL OPERATING EXPENSES**	**643 000**	**603,200**	**619 700**	**1 865 900**
20	**MAINTENANCE EXPENSES**				
21	VEHICLE REPAIRS AND MAINTENANCE	8 000	20 000	12 000	40 000
22	REPAIR FUND	100 000	835 428	777 018	1 712 446
23	**TOTAL MAINTENANCE EXPENSES**	**108 000**	**855 428**	**789 018**	**1 752 446**
24	DEPRECIATION (Used 3 33 % on Gov Appraised Value)	18 681	2 743 754	1 202 630	3 965 064
25	**TAXES OTHER THAN PROFIT TAXES**				
26	CUSTOMS FEES	140 000	0	0	140 000
27	PROPERTY TAX (Used 0 6% on 1998 Government Valuation)	3 366	494 370	216 690	714 426
28	SOCIAL TAXES (Cap at 11 584/Employee/Month)	36 000	79 560	144 000	259 560
29	TOTAL OTHER TAXES	179 366	573 930	360 690	1 113 986
30	**INTEREST ON SHORT TERM LOANS**	**100 000**	**0**	**0**	**100 000**
31	**INTEREST ON LONG TERM DEBT**	**800 000**	**0**	**0**	**800 000**
32	**TOTAL OPERATING COSTS**	**1 849 047**	**4 776,312**	**2 972 038**	**9 597 396**
33	CURRENT ASSET VALUE Millions of Drams 1998 Valuation	561	82 395	36 115	119 071
34	CURRENT ASSET VALUE $ Millions 1998 Valuation	1 12	164 79	72 23	238 14
35	DEPRECIATION (used 3 33% Based on Assumed Life Cycle of 30 Years)	3 33%	3 33%	3 33%	

Note Light Frames on Lines Denote Payments to or Collections by State
Heavy Frames on Lines Denote Changes from Schedule B-2

NATURAL GAS ENTERPRISES
ARMROSGASPROM PLAN
For the 12-Month Period Ending June 30 1999

CHANGE BASE CASE (1) INTEREST ON L T DEBT IN O&M COSTS (2) ADD PROPERTY TAX 1998 VALUATION (3) ADD DEPRECIATION

		ARMROS GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL
		THOUSANDS OF ARMENIAN DRAMS			
50	Volume Received 1000 Standard Cubic Meters	1 672 500	1 672 500	1 608 945	1 672 500
51	Losses %	0	3 80%	1 68%	5 48%
52	Volume Delivered 1000 Standard Cubic Meters	1 672 500	1 608 945	1 581 915	1 581 915
53	Price Charged by Importer $/MCM	55 00			
54	Amount Payable to Importer $ Millions	91 988			
55	VAT %	20%			
56	Amount Payable to State Due to VAT $ Millions	18 3975			
57	Total Amount Import Costs plus VAT $ Million	110 385			
58	Equivalent Tariff upon Receipt of Gas $/MCM	66 000	68 750	78 788	84 899
59	TOTAL OPERATING COSTS (From Preceding Page)	1 849 047	4 776 312	2 972 038	9 597 396
60	After Tax Profit (No Interest on Long Term Debt) Thousands of Drams	50 500	99 431	126 212	276 142
61	Profit Before Profit Tax (No Interest on Long Term Debt) Thousands of Drams	67 333	132 574	168 282	368 189
62	Total Operating Cost + Profit Before Profit Tax Subject to VAT 10^3 Drams	1 916 381	4 908 886	3 140 320	9 965 586
63	Total Amount After VAT and Profit Tax (Total Additional Revenue Requirement)	2 299 657	5 890 663	3 768 383	11 958 703
64	VAT on Company Operations Thousands of Drams	383 276	981 777	628 064	1 993 117
65	Profit Tax Rate %	25 0%	25 0%	25 0%	
66	Tax on Profits Thousands of Drams	16 833	33 144	42 071	92 047
		MILLIONS OF DOLLARS			
67	Total Operating Costs $ Millions	3 698	9 553	5 944	19 195
68	After-Tax Profit (No Interest on Long Term Debt) $ Millions	0 101	0 199	0 252	0 552
69	Profit Before Profit Tax (No Interest on Long Term Debt) Thousands of Drams	0 135	0 265	0 337	0 736
70	Total Operating Cost + Profit Before Profit Tax Subject to VAT $ Millions	3 833	9 818	6 281	19 931
71	Total Amount After VAT and Profit Tax (Total Additional Revenue Requirement)	4 599	11 781	7 537	23 917
72	VAT on Company Operations $ Millions	0 767	1 964	1 256	3 986
73	Tax on Profits $ Millions	0 034	0 066	0 084	0 184
74	Total Invoice $ Millions	114 984	126 766	134 302	134 302
75	Overall Tariff $/MCM	68 750	78 788	84 899	84 899
76	Incremental Tariff $/MCM	2 750	10 038	6 111	18 899
		CLAIMS ON NATURAL GAS EXPENDITURES			
	Total Claims $ Millions				
77	Amount Payable to Importer	91 988	0 000	0 000	91 988
78	Claims by State Including Other Taxes	19 556	3 178	2 062	24 796
79	Operating Costs Excluding Other Taxes	3 339	8 405	5 223	16 967
80	Claims by Shareholders (After Tax Profits No Interest on L-T Debt)	0 101	0 199	0 252	0 552
81	Total Charges	114 984	11 781	7 537	134 302
82	Armenian Charges	22 997	11 781	7 537	42 315
	Claims % of Total Costs				
83	Amount Payable to Importer	80 0%	0 0%	0 0%	68 5%
84	Claims by State	17 0%	27 0%	27 4%	18 5%
85	Operating Costs	2 9%	71 3%	69 3%	12 6%
86	Claims by Shareholders (After Tax Profits No Interest on L T Debt)	0 1%	1 7%	3 3%	0 4%
87	Total Claims	100 0%	100 0%	100 0%	100 0%
	Claims % of Costs Added in Armenia				
88	Claims by State	85 0%	27 0%	27 4%	58 6%
89	Operating Costs	14 5%	71 3%	69 3%	40 1%
90	Claims by Shareholders (After-Tax Profits No Interest on L T Debt)	0 4%	1 7%	3 3%	1 3%
91	Total Claims	100 0%	100 0%	100 0%	100 0%
	Claims % of Costs Added in Armenia with State as Only Shareholder				
92	Claims by State	85 5%	28 7%	30 7%	59 9%
93	Operating Costs	14 5%	71 3%	69 3%	40 1%
94	Total Claims	100 0%	100 0%	100 0%	100 0%
95	Rate of Return	9 00%	0 12%	0 35%	0.23%
96	Depreciation Accrual Rate	3 33%	3 33%	3 33%	3 33%

Note Light Frames on Lines Denote Payments to or Collections by State
Heavy Frames on Lines Denote Changes from Schedule B 2

NATURAL GAS ENTERPRISES

ARMROSGASPROM PLAN

For the 12-Month Period Ending June 30 1999

CHANGE (1) INT ON L T DEBT IN O&M COSTS (2) PROP TAX 1998 VALUE (3) DEPRECIATION 1998 VALUE (4) BAD DEBT RESERVE 5%

	REVENUE REQUIREMENTS	ARMROS GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL
		THOUSANDS OF ARMENIAN DRAMS			
1	OPERATING EXPENSES				
2	MATERIALS AND RAW MATERIALS	10 000	100 000	20 000	130 000
3	SALARY FUND	100 000	221 000	400 000	721 000
4	ELECTRICITY CONSUMPTION	18 000	96 000	22 000	136 000
5	FUEL CONSUMPTION	20 000	74 000	45 000	139 000
6	TECHNOLOGICAL LOSSES	0	0	0	0
7	PERSONNEL TRAINING	1 000	3 800	5 000	9 800
8	TRAVEL EXPENSES	28 000	10 000	3 400	41 400
9	RENT	1 000	0	10 000	11 000
10	CATHODIC PROTECTION	0	7 400	22 600	30 000
11	TELEPHONE CHARGES	34 000	8 000	10 000	52 000
12	COMMUNAL UTILITIES CHARGES	4 000	10 000	6 000	20 000
13	AUDIT SERVICES	20 000	9 000	17 000	46 000
14	BANKING SERVICES	332 000	6 000	11 000	349 000
15	MARKETING SERVICES	50 000	0	0	50 000
16	BAD DEBT RESERVE (USED 5 0%)	0	0	3 571 872	3 571 872
17	PROTECTION FROM NATURAL CALAMITY	3 000	46 000	33 000	82 000
18	OTHER EXPENDITURES	22 000	12 000	14 700	48 700
19	**TOTAL OPERATING EXPENSES**	**643 000**	**603 200**	**4 191 572**	**5 437 772**
20	MAINTENANCE EXPENSES				
21	VEHICLE REPAIRS AND MAINTENANCE	8 000	20 000	12 000	40 000
22	REPAIR FUND	100 000	835 428	777 018	1 712 446
23	**TOTAL MAINTENANCE EXPENSES**	**108 000**	**855 428**	**789 018**	**1 752 446**
24	**DEPRECIATION (Used 3.33 % on Gov Appraised Value)**	**18 681**	**2 743 754**	**1 202 630**	**3 965 064**
25	TAXES OTHER THAN PROFIT TAXES				
26	CUSTOMS FEES	140 000	0	0	140 000
27	PROPERTY TAX (Used 0 6% on 1998 Government Valuation)	3 366	494 370	216 690	714 426
28	SOCIAL TAXES (Cap at 11 584/Employee/Month)	36 000	79 560	144 000	259 560
29	TOTAL OTHER TAXES	179 366	573 930	360 690	1 113 986
30	**INTEREST ON SHORT TERM LOANS**	**100 000**	**0**	**0**	**100 000**
31	**INTEREST ON LONG TERM DEBT**	**800 000**	**0**	**0**	**800 000**
32	**TOTAL OPERATING COSTS**	**1 849 047**	**4 776 312**	**6 543 910**	**13 169 268**
33	CURRENT ASSET VALUE Millions of Drams 1998 Valuation	561	82 395	36 115	119 071
34	CURRENT ASSET VALUE $ Millions 1998 Valuation	1 12	164 79	72 23	238 14
35	DEPRECIATION (used 3 33% Based on Assumed Life Cycle of 30 Years)	3 33%	3 33%	3 33%	

Note Light Frames on Lines Denote Payments to or Collections by State
Heavy Frames on Lines Denote Changes from Schedule C-2

NATURAL GAS ENTERPRISES
ARMROSGASPROM PLAN
For the 12-Month Period Ending June 30 1999

CHANGE (1) INT ON L T DEBT IN O&M COSTS (2) PROP TAX 1998 VALUE (3) DEPRECIATION 1998 VALUE (4) BAD DEBT RESERVE 5%

		ARMROS GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL
		THOUSANDS OF ARMENIAN DRAMS			
50	Volume Received 1000 Standard Cubic Meters	1 672 500	1 672 500	1 608 945	1 672 500
51	Losses %	0	3 80%	1 68%	5 48%
52	Volume Delivered 1000 Standard Cubic Meters	1 672 500	1 608 945	1 581 915	1 581 915
53	Price Charged by Importer $/MCM	55 00			
54	Amount Payable to Importer $ Millions	91 988			
55	VAT %	20%			
56	Amount Payable to State Due to VAT $ Millions	18 3975			
57	Total Amount Import Costs plus VAT $ Million	110 385			
58	Equivalent Tariff upon Receipt of Gas $/MCM	66 000	68 750	78 788	90 318
59	**TOTAL OPERATING COSTS (From Preceding Page)**	1 849 047	4 776 312	6 543 910	13 169 268
60	After Tax Profit (No Interest on Long Term Debt) Thousands of Drams	50 500	99 431	126 212	276 142
61	Profit Before Profit Tax (No Interest on Long Term Debt) Thousands of Drams	67 333	132 574	168 282	368 189
62	Total Operating Cost + Profit Before Profit Tax Subject to VAT 10^3 Drams	1 916 381	4 908 886	6 712 192	13 537 458
63	Total Amount After VAT and Profit Tax (Total Additional Revenue Requirement)	2 299 657	5 890 663	8 054 630	16 244 949
64	VAT on Company Operations Thousands of Drams	383,276	981 777	1 342 438	2 707 492
65	Profit Tax Rate %	25 0%	25 0%	25 0%	
66	Tax on Profits Thousands of Drams	16 833	33 144	42 071	92 047
		MILLIONS OF DOLLARS			
67	Total Operating Costs $ Millions	3 698	9 553	13 088	26 339
68	After Tax Profit (No Interest on Long Term Debt) $ Millions	0 101	0 199	0 252	0 552
69	Profit Before Profit Tax (No Interest on Long-Term Debt) Thousands of Drams	0 135	0 265	0 337	0 736
70	Total Operating Cost + Profit Before Profit Tax Subject to VAT $ Millions	3 833	9 818	13 424	27 075
71	Total Amount After VAT and Profit Tax (Total Additional Revenue Requirement)	4 599	11 781	16 109	32 490
72	VAT on Company Operations $ Millions	0 767	1 964	2 685	5 415
73	Tax on Profits $ Millions	0 034	0 066	0 084	0 184
74	Total Invoice $ Millions	114 984	126 766	142 875	142 875
75	Overall Tariff $/MCM	68 750	78 788	90 318	90 318
76	Incremental Tariff $/MCM	2 750	10 038	11 530	24 318
		CLAIMS ON NATURAL GAS EXPENDITURES			
	Total Claims $ Millions				
77	Amount Payable to Importer	91 988	0 000	0 000	91 988
78	Claims by State Including Other Taxes	19 556	3 178	3 490	26 225
79	Operating Costs Excluding Other Taxes	3 339	8 405	12 366	24 111
80	Claims by Shareholders (After Tax Profits No Interest on L T Debt)	0 101	0 199	0 252	0 552
81	Total Charges	114 984	11 781	16 109	142 875
82	Armenian Charges	22 997	11 781	16 109	50 887
	Claims % of Total Costs				
83	Amount Payable to Importer	80 0%	0 0%	0 0%	64 4%
84	Claims by State	17 0%	27 0%	21 7%	18 4%
85	Operating Costs	2 9%	71 3%	76 8%	16 9%
86	Claims by Shareholders (After Tax Profits No Interest on L T Debt)	0 1%	1 7%	1 6%	0 4%
87	Total Claims	100 0%	100 0%	100 0%	100 0%
	Claims % of Costs Added in Armenia				
88	Claims by State	85 0%	27 0%	21 7%	51 5%
89	Operating Costs	14 5%	71 3%	76 8%	47 4%
90	Claims by Shareholders (After Tax Profits No Interest on L T Debt)	0 4%	1 7%	1 6%	1 1%
91	Total Claims	100 0%	100 0%	100 0%	100 0%
	Claims % of Costs Added in Armenia with State as Only Shareholder				
92	Claims by State	85 5%	28 7%	23 2%	52 6%
93	Operating Costs	14 5%	71 3%	76 8%	47 4%
94	Total Claims	100 0%	100 0%	100 0%	100 0%
95	Rate of Return	9 00%	0 12%	0 35%	0 23%
96	Depreciation Accrual Rate	3 33%	3 33%	3 33%	3 33%

Note Light Frames on Lines Denote Payments to or Collections by State
Heavy Frames on Lines Denote Changes from Schedule C 2

NATURAL GAS ENTERPRISES
ARMROSGASPROM PLAN
For the 12-Month Period Ending June 30 1999

CHANGE (1) INT ON L T DEBT IN O&M COSTS (2) PROP TAX 1998 VALUE (3) DEPRECIATION 1998 VALUE (4) RETURN = 15% OF RATE BASE

		ARMROS GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL
	REVENUE REQUIREMENTS	THOUSANDS OF ARMENIAN DRAMS			
1	OPERATING EXPENSES				
2	MATERIALS AND RAW MATERIALS	10 000	100 000	20 000	130 000
3	SALARY FUND	100 000	221 000	400 000	721 000
4	ELECTRICITY CONSUMPTION	18 000	96 000	22 000	136 000
5	FUEL CONSUMPTION	20 000	74 000	45 000	139 000
6	TECHNOLOGICAL LOSSES	0	0	0	0
7	PERSONNEL TRAINING	1 000	3 800	5 000	9 800
8	TRAVEL EXPENSES	28 000	10 000	3 400	41 400
9	RENT	1 000	0	10 000	11 000
10	CATHODIC PROTECTION	0	7 400	22 600	30 000
11	TELEPHONE CHARGES	34 000	8 000	10 000	52 000
12	COMMUNAL UTILITIES CHARGES	4 000	10 000	6 000	20 000
13	AUDIT SERVICES	20 000	9 000	17 000	46 000
14	BANKING SERVICES	332 000	6 000	11 000	349 000
15	MARKETING SERVICES	50 000	0	0	50 000
16	BAD DEBT RESERVE (USED 0 0%)	0	0	0	0
17	PROTECTION FROM NATURAL CALAMITY	3 000	46 000	33 000	82 000
18	OTHER EXPENDITURES	22 000	12 000	14 700	48 700
19	TOTAL OPERATING EXPENSES	643 000	603,200	619 700	1 865 900
20	MAINTENANCE EXPENSES				
21	VEHICLE REPAIRS AND MAINTENANCE	8 000	20 000	12 000	40 000
22	REPAIR FUND	100 000	835 428	777 018	1 712 446
23	TOTAL MAINTENANCE EXPENSES	108 000	855 428	789 018	1 752 446
24	DEPRECIATION (Used 3 33 % on Gov Appraised Value)	18 681	2 743 754	1 202 630	3 965 064
25	TAXES OTHER THAN PROFIT TAXES				
26	CUSTOMS FEES	140 000	0	0	140 000
27	PROPERTY TAX (Used 0 6% on 1998 Government Valuation)	3 366	494 370	216 690	714 426
28	SOCIAL TAXES (Cap at 11 584/Employee/Month)	36 000	79 560	144 000	259 560
29	TOTAL OTHER TAXES	179 366	573 930	360 690	1 113 986
30	INTEREST ON SHORT TERM LOANS	100 000	0	0	100 000
31	INTEREST ON LONG TERM DEBT	800 000	0	0	800 000
32	TOTAL OPERATING COSTS	1 849 047	4 776 312	2 972 038	9 597 396
33	CURRENT ASSET VALUE Millions of Drams 1998 Valuation	561	82 395	36 115	119 071
34	CURRENT ASSET VALUE $ Millions 1998 Valuation	1 12	164 79	72 23	238 14
35	DEPRECIATION (used 3 33% Based on Assumed Life Cycle of 30 Years)	3 33%	3 33%	3 33%	

Note Light Frames on Lines Denote Payments to or Collections by State
Heavy Frames on Lines Denote Changes from Schedule D-2

NATURAL GAS ENTERPRISES
ARMROSGASPROM PLAN
For the 12 Month Period Ending June 30 1999

CHANGE (1) INT ON L T DEBT IN O&M COSTS (2) PROP TAX & (3) DEPRECIATION 1998 VALUE (4) RETURN = 15% OF RATE BASE

		ARMROS GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL
		THOUSANDS OF ARMENIAN DRAMS			
50	Volume Received 1000 Standard Cubic Meters	1 672 500	1 672 500	1 608 945	1 672 500
51	Losses %	0	3 80%	1 68%	5 48%
52	Volume Delivered 1000 Standard Cubic Meters	1 672 500	1 608 945	1 581 915	1 581 915
53	Price Charged by Importer $/MCM	55 00			
54	Amount Payable to Importer $ Millions	91 988			
55	VAT %	20%			
56	Amount Payable to State Due to VAT $ Millions	18 398			
57	Total Amount Import Costs plus VAT $ Million	110 385			
58	Equivalent Tariff upon Receipt of Gas $/MCM	66 000	68 814	103 238	103 238
59	TOTAL OPERATING COSTS (From Preceding Page)	1 849 047	4 776 312	2 972 038	9 597 396
60	Rate of Return on Assets (% of Asset Base)	15 0%	15 0%	15 0%	
61	Asset Base (From Preceding Page)	561 000	82 395 000	36 115 000	119 071 000
62	After Tax Profit (Return on Assets)	84 150	12 359 250	5 417 250	17 860 650
63	Profit Tax Rate %	25 0%	25 0%	25 0%	
64	Profit Before Profit Tax	112 200	16 479 000	7 223 000	23 814 200
65	Total Operating Cost + Profit Before Profit Tax Subject to VAT	1 961 247	21 255 312	10 195 038	33 411 596
66	Total Amount After VAT and Profit Tax (Total Additional Revenue Requiremen	2 353 497	25 506 374	12 234 045	40 093 916
67	VAT on Company Operations	392 249	4 251 062	2 039 008	6 682 319
68	Profit Tax	28 050	4 119 750	1 805 750	5 953 550
69	Profit (Check Only Not Operative)	84 150	12 359 250	5 417 250	17 860 650
		Millions of Dollars			
70	Total Operating Costs	3 698	9 553	5 944	19 19
71	After Tax Profit (Return on Assets)	0 168	24 719	10 835	35 72
72	Total Amount After VAT and Profit Tax (Total Additional Revenue Requiremen	4 707	51 013	24 468	80 19
73	VAT on Company Operations	0 784	8 502	4 078	13 36
74	Before Tax Profit on Company Operations	0 224	32 958	14 446	47 63
75	Profit Tax	0 056	8 240	3 612	11 907
76	Profit (Check Only Not Operative)	0 168	24 719	10 835	35 721
77	Total Invoice	115 092	166 105	190 573	190 573
78	Overall Tariff $/MCM	68 814	103 238	120 470	120 470
79	Incremental Tariff $/MCM	2 814	34 424	17 231	54 470
80	Total Claims $ Millions				
81	Amount Payable to Importer	91 988	0 000	0 000	91 988
82	Claims by State Including Other Taxes	19 597	17 889	8 411	45 897
83	Operating Costs Excluding Other Taxes	3 339	8 405	5 223	16 967
84	Claims by Shareholders (After Tax Profits)	0 168	24 719	10 835	35 721
85	Total Charges	115 092	51 013	24 468	190 573
86	Armenian Charges	23 10	51 01	24 47	98 59
87	Claims % of Total Costs				
88	Claims by Importer	79 9%	0 0%	0 0%	48 3%
89	Claims by State	17 0%	35 1%	34 4%	24 1%
90	Operating Costs	2 9%	16 5%	21 3%	8 9%
91	Claims by Shareholders (After Tax Profits)	0 1%	48 5%	44 3%	18 7%
92	Total Claims	100 0%	100 0%	100 0%	100 0%
93	Claims % of Costs Added in Armenia				
94	Claims by State	84 8%	35 1%	34 4%	46 6%
95	Operating Costs	14 5%	16 5%	21 3%	17 2%
96	Claims by Shareholders	0 7%	48 5%	44 3%	36 2%
97	Total Claims	100 0%	100 0%	100 0%	100 0%
98	Claims % of Costs Added in Armenia with State as Only Shareholder				
99	Claims by State	85 5%	83 5%	78 7%	82 8%
100	Operating Costs	14 5%	16 5%	21 3%	17 2%
101	Total Claims	100 0%	100 0%	100 0%	100 0%
102	Rate of Return	15 00%	15 00%	15 00%	15 00%
103	Depreciation Accrual Rate	3 33%	3 33%	3 33%	3 33%

Note Light Frames on Lines Denote Payments to or Collections by State
Heavy Frames on Lines Denote Changes from Schedule D-2

NATURAL GAS ENTERPRISES
ARMGASPROM PLAN
For the 12-Month Period Ending June 30, 1999

CHANGE (1) INT ON L T DEBT IN O&M COSTS (2) PROP TAX 1998 VALUE (3) DEPRECIATION 1998 VALUE
(4) RETURN = 15% OF RATE BASE (5) US OPERATING NORMS

	REVENUE REQUIREMENTS	ARM GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL
		THOUSANDS OF ARMENIAN DRAMS			
1	OPERATING EXPENSES				
2	SUPPLIES AND RAW MATERIALS	10 000	100 000	20 000	130 000
3	SALARY FUND	100 000	221 000	400 000	721 000
4	ELECTRICITY CONSUMPTION	18 000	96 000	22 000	136 000
5	FUEL CONSUMPTION	20 000	74 000	45 000	721 000
6	TECHNOLOGICAL LOSSES	0	0	0	0
7	PERSONNEL TRAINING	1 000	3 800	5 000	9 800
8	TRAVEL EXPENSES	28 000	10 000	3 400	41 400
9	RENT	1 000	0	10 000	11 000
10	CATHODIC PROTECTION	0	7 400	22 600	41 400
11	TELEPHONE CHARGES	34 000	8 000	10 000	52 000
12	COMMUNAL UTILITIES CHARGES	4 000	10 000	6 000	20 000
13	AUDIT SERVICES	20 000	9 000	17 000	46 000
14	BANKING SERVICES	332 000	6 000	11 000	349 000
15	MARKETING SERVICES	50 000	0	0	50 000
16	BAD DEBT RESERVE (USED 0 0%)	0	0	0	0
17	PROTECTION FROM NATURAL CALAMITY	3 000	46 000	33 000	82 000
18	OTHER EXPENDITURES	22 000	12 000	14 700	48 700
19	TOTAL OPERATING EXPENSES	643 000	603 200	619 700	1 865 900
20	MAINTENANCE EXPENSES				
21	VEHICLE REPAIRS AND MAINTENANCE	8 000	20 000	12 000	40 000
22	REPAIR FUND	100 000	835 428	777 018	1 712 446
23	TOTAL MAINTENANCE EXPENSES	108 000	855 428	789 018	1 752 446
24	TOTAL OPERATING AND MAINTENANCE EXPENSES	751 000	1 458 628	1 408 718	3 618 346
25	ADJUSTMENT FOR US COSTS	1 224 239	903 033	2 899 980	5 027 252
26	TOTAL ADJUSTED OPERATING EXPENSES	1 975 239	2 361 661	4 308 698	8 645 598
27	DEPRECIATION (Used 3 33 % on Gov Appraised Value)	18 681	2 743 754	1 202 630	3 965 064
28	TAXES OTHER THAN PROFIT TAXES				
29	CUSTOMS FEES	140 000	0	0	140 000
30	PROPERTY TAX (Used 0 6% on 1998 Government Valuation)	3 366	494 370	216 690	714 426
31	SOCIAL TAXES (Cap at 11 584/Employee/Month)	36 000	79 560	144 000	259 560
32	TOTAL OTHER TAXES	179 366	573 930	360 690	1 113 986
33	INTEREST ON SHORT TERM LOANS	100 000	0	0	100 000
34	INTEREST ON LONG TERM DEBT	800 000	0	0	800 000
35	TOTAL OPERATING COSTS	3 073 286	5 679 345	5 872 018	14 624 648
36	CURRENT ASSET VALUE Millions of Drams 1998 Valuation	561	82 395	36 115	119 071
37	CURRENT ASSET VALUE $ Millions 1998 Valuation	1 12	164 79	72 23	238 14
38	DEPRECIATION (used 3 33% Based on Assumed Life Cycle of 30 Years)	3 33%	3 33%	3 33%	

Note Light Frames on Lines Denote Payments to or Collections by State
Heavy Frames on Lines Denote Changes from Schedule D-2

NATURAL GAS ENTERPRISES

ARMGASPROM PLAN

For the 12-Month Period Ending June 30 1999

CHANGE (1) INT ON L T DEBT IN O&M COSTS (2) PROP TAX 1998 VALUE (3) DEPRECIATION 1998 VALUE
(4) RETURN = 15% OF RATE BASE (5) US OPERATING NORMS

		ARM GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL
50	Volume Received 1000 Standard Cubic Meters	1 672 500	1 672 500	1 608 945	1 672 500
51	Losses %	0	3 80%	1 68%	5 48%
52	Volume Delivered 1000 Standard Cubic Meters	1 672 500	1 608 945	1 581 915	1 581 915
53	Price Charged by Importer $/MCM	55 00			
54	Amount Payable to Importer $ Millions	91 988			
55	VAT %	20%			
56	Amount Payable to State Due to VAT $ Millions	18 398			
57	Total Amount Import Costs plus VAT $ Million	110 385			
58	Equivalent Tariff upon Receipt of Gas $/MCM	66 000	70 571	106 411	106 411
		THOUSANDS OF ARMENIAN DRAMS			
59	**TOTAL OPERATING COSTS (From Preceding Page)**	3 073 286	5 679 345	5 872 018	14 624 648
60	Rate of Return on Assets (% of Asset Base)	15 0%	15%	15 0%	
61	Asset Base (From Preceding Page)	561 000	82 395 000	36 115 000	119 071 000
62	After Tax Profit (Return on Assets)	84 150	12 359 250	5 417 250	17 860 650
63	Profit Tax Rate %	25 0%	25 0%	25 0%	
64	Profit Before Profit Tax	112 200	16 479 000	7 223 000	23 814 200
65	Total Operating Cost + Profit Before Profit Tax Subject to VAT	3 185 486	22 158 345	13 095 018	38 438 848
66	Total Amount After VAT and Profit Tax (Total Additional Revenue Requireme	3 822 584	26 590 013	15 714 021	46 126 618
67	VAT on Company Operations	637 097	4 431 669	2 619 004	7 687 770
68	Profit Tax	28 050	4 119 750	1 805 750	5 953 550
69	Profit (Check Only Not Operative)	84 150	12 359 250	5 417 250	17 860 650
		MILLIONS OF US DOLLARS			
70	Total Operating Costs	6 147	11 359	11 744	29 25
71	After Tax Profit (Return on Assets)	0 168	24 719	10 835	35 72
72	Total Amount After VAT and Profit Tax (Total Additional Revenue Requireme	7 645	53 180	31 428	92 25
73	VAT on Company Operations	1 274	8 863	5 238	15 38
74	Before Tax Profit on Company Operations	0 224	32 958	14 446	47 63
75	Profit Tax	0 056	8 240	3 612	11 907
76	Profit (Check Only Not Operative)	0 168	24 719	10 835	35 721
77	Total Invoice	118 030	171 210	202 638	202 638
78	Overall Tariff $/MCM	70 571	106 411	128 097	128 097
79	Incremental Tariff $/MCM	4 571	35 840	21 685	62 097
80	Total Claims $ Millions				
81	Amount Payable to Importer	91 988	0 000	0 000	91 988
82	Claims by State Including Other Taxes	20 087	18 251	9 571	47 908
83	Operating Costs Excluding Other Taxes	5 788	10 211	11 023	27 021
84	Claims by Shareholders (After Tax Profits)	0 168	24 719	10 835	35 721
85	Total Charges	118 030	53 180	31 428	202 638
86	Armenian Charges	26 04	53 18	31 43	110 65
87	Claims % of Total Costs				
88	Claims by Importer	77 9%	0 0%	0 0%	45 4%
89	Claims by State	17 0%	34 3%	30 5%	23 6%
90	Operating Costs	4 9%	19 2%	35 1%	13 3%
91	Claims by Shareholders (After Tax Profits)	0 1%	46 5%	34 5%	17 6%
92	Total Claims	100 0%	100 0%	100 0%	100 0%
93	Claims % of Costs Added in Armenia				
94	Claims by State	77 1%	34 3%	30 5%	43 3%
95	Operating Costs	22 2%	19 2%	35 1%	24 4%
96	Claims by Shareholders	0 6%	46 5%	34 5%	32 3%
97	Total Claims	100 0%	100 0%	100 0%	100 0%
98	Claims % of Costs Added in Armenia with State as Only Shareholder				
99	Claims by State	77 8%	80 8%	64 9%	75 6%
100	Operating Costs	22 2%	19 2%	35 1%	24 4%
101	Total Claims	100 0%	100 0%	100 0%	100 0%
102	Rate of Return	15 00%	15 00%	15 00%	15 00%
103	Depreciation Accrual Rate	3 33%	3 33%	3 33%	3 33%

Note Light Frames on Lines Denote Payments to or Collections by State
Heavy Frames on Lines Denote Changes from Schedule D-2

Table 3-A

ARMENIAN NATURAL GAS TARIFFS
UNDER DIFFERENT SCENARIOS
SUMMARY OF RESULTS

SCHED		ARM GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL	Average Delivered Price	Average Delivered Price
		US Dollars per 1000 Standard Cubic Meters					$/MCF
ERC	BASE CASE Using Energy Regulatory Commission Data	3 23	5 40	3 96	12 60	78 60	2 23
ERC-2	CHANGE FROM BASE CASE Interest on L T Debt Moved into O&M Costs	2 73	5 38	3 95	12 07	78 07	2 21
A 2	CHANGE FROM BASE L T Debt into Costs and Property Tax on Old Values	2 73	5 41	3 96	12 10	78 10	2 21
B-2	CHANGE FROM BASE L T Debt into Costs and Property Tax on 1998 Values	2 73	6 12	4 29	13 15	79 15	2 24
C-2	CHANGE FROM BASE L T Debt into Costs Property Tax on 1998 Values, Depreciation	2 75	10 04	6 11	18 90	84 90	2 41
D-2	CHANGE FROM BASE L T Debt into Costs Property Tax on 1998 Values, Depreciation, Bad Debt Reserve	2 75	10 04	11 53	24 32	90 32	2 56
E 2	CHANGE FROM BASE L T Debt=Costs Prop Tax on 98 Values, Depreciation, RoR on Asset Base	2 81	34 42	17 23	54 47	120 47	3 41
F 2	CHANGE FROM BASE L T Debt=Costs Prop Tax on 98 Values Depreciation, 15% RoR on Asset Base, US Cost	4 57	35 84	21 69	62 10	128 10	3 63

Table 3-B

COMPARATIVE NATURAL GAS PRICES
US VERSUS ARMENIA

	DELIVERED PRICES				
	US		ARMENIA		
	$/MCM	$/MCF	$/MCM	$/MCF	
At Wellhead/Armenian Border	76 63	2 17	66 00	1 87	Armenian Border
At City Gate	115 48	3 27	74 63	2 11	Base Case
			106 41	3 01	Most Expensive Case (F 2)
Delivered to Consumers					
Residential	223 89	6 34	78 60	2 23	Base Case All Consumers
Commercial	190 70	5 40	128 10	3 63	Most Expensive All Consumers
Industrial	120 78	3 42			
Electric Utilities	95 00	2 69			
Vehicle Fuel	153 27	4 34			
Weighted Average Consumer Price	155 31	4 40			
	INCREMENTAL TARIFFS				
	US		ARMENIA		
	$/MCM	$/MCF	$/MCM	$/MCF	
Wellhead (Border) to City Gate	38 85	1 10	8 63	0 24	Base Case
			40 41	1 14	Most Expensive Case (F 2)
City Gate to Consumer	39 83	1 13	3 96	0 11	Base Case
			21 69	0 61	Most Expensive Case (F 2)

Table 4-A

CLAIMS ON ARMENIAN FUNDS TOTAL AMOUNTS GENERATED IN THE NATURAL GAS INDUSTRY SUMMARY OF RESULTS

SCHED		Funds Accruing to Importer	Funds Accruing to Armenia	Claims on Armenian Funds Companies	Taxes	Shareholder	Total State
		Millions of Dollars per Year					
ERC	BASE CASE Using Energy Regulatory Commission Data	91 99	32 34	7 79	22 28	2 27	24 55
ERC-2	CHANGE FROM BASE CASE Interest on L T Debt Moved into O&M Costs	91 99	31 51	9 39	21 57	0 55	22 12
A-2	CHANGE FROM BASE. L T Debt into Costs and Property Tax on Old Values	91 99	31 57	9 39	21 62	0 55	22 18
B-2	CHANGE FROM BASE L T Debt into Costs and Property Tax on 1998 Values	91 99	33 22	9 39	23 28	0 55	23 83
C-2	CHANGE FROM BASE L T Debt into Costs Property Tax on 1998 Values, Depreciation	91 99	42.31	16 97	24 80	0 55	25 35
D-2	CHANGE FROM BASE. L T Debt into Costs Property Tax on 1998 Values, Depreciation, Bad Debt Reserve	91 99	50 89	24 11	26 22	0 55	26 78
E 2	CHANGE FROM BASE. L T Debt=Costs Prop Tax on 98 Values Depreciation, RoR on Asset Base	91 99	98 59	16 97	45 90	35 72	81 62
F 2	CHANGE FROM BASE L T Debt=Costs Prop Tax on '98 Values Depreciation, 15% RoR on Asset Base, US Cost Norms	91 99	110 65	27 02	47 91	35 72	83 63

Table 4-B

CLAIMS ON ARMENIAN FUNDS PERCENT GENERATED IN THE NATURAL GAS INDUSTRY SUMMARY OF RESULTS

SCHED		Funds Accruing to Importer	Funds Accruing to Armenia	Claims on Armenian Funds Companies	Taxes	Shareholder	Total State
		Millions of Dollars per Year		Percent			
ERC	BASE CASE Using Energy Regulatory Commission Data	91 99	32 34	24 1%	68 9%	7 0%	75 9%
ERC 2	CHANGE FROM BASE CASE Interest on L T Debt Moved into O&M Costs	91 99	31 51	29 8%	68 4%	1 8%	70 2%
A 2	CHANGE FROM BASE L T Debt into Costs and Property Tax on Old Values	91 99	31 57	29 7%	68 5%	1 7%	70 3%
B-2	CHANGE FROM BASE L T Debt into Costs and Property Tax on 1998 Values	91 99	33 22	28 3%	70 1%	1 7%	71 7%
C 2	CHANGE FROM BASE L T Debt into Costs Property Tax on 1998 Values, Depreciation	91 99	42 31	40 1%	58 6%	1 3%	59 9%
D-2	CHANGE FROM BASE L T Debt into Costs Property Tax on 1998 Values, Depreciation, Bad Debt Reserve	91 99	50 89	47 4%	51 5%	1 1%	52 6%
E 2	CHANGE FROM BASE L T Debt=Costs Prop Tax on '98 Values Depreciation, RoR on Asset Base	91 99	98 59	17 2%	46 6%	36 2%	82 8%
F 2	CHANGE FROM BASE L T Debt=Costs Prop Tax on '98 Values Depreciation, 15% RoR on Asset Base, US Cost Norms	91 99	110 65	24 4%	43 3%	32 3%	75 6%

Table 5

CLAIMS ON FUNDS AND RATES OF RETURN GENERATED IN THE NATURAL GAS INDUSTRY SUMMARY OF RESULTS

SCHED		Armenian Funds Total	Companies	Companies	Rate of Return on Assets
		Millions of Dollars per Year		% of Total	%
ERC	BASE CASE Using Energy Regulatory Commission Data	32 34	7 79	24 1%	28 42%
ERC-2	CHANGE FROM BASE CASE Interest on L T Debt Moved into O&M Costs	31 51	9 39	29 8%	6 90%
A-2	CHANGE FROM BASE L-T Debt into Costs and Property Tax on Old Values	31 57	9 39	29 7%	6 90%
B-2	CHANGE FROM BASE L-T Debt into Costs and Property Tax on 1998 Values	33 22	9 39	28 3%	0 23%
C-2	CHANGE FROM BASE L-T Debt into Costs Property Tax on 1998 Values Depreciation	42 31	16 97	40 1%	0 23%
D 2	CHANGE FROM BASE L-T Debt into Costs Property Tax on 1998 Values Depreciation Bad Debt Reserve	50 89	24 11	47 4%	0 23%
E 2	CHANGE FROM BASE L-T Debt=Costs Prop Tax on 98 Values Depreciation, RoR on Asset Base	98 59	16 97	17 2%	15 00%
F-2	CHANGE FROM BASE L-T Debt=Costs Prop Tax on 98 Values, Depreciation 15% RoR on Asset Base US Cost	110 65	27 02	24 4%	15 00%

Chapter

3

The Impact of Suggested Changes

The Target And How to Get There From Here

The Target

From the data developed in Chapter 2, we can now construct proforma income statements for the three component companies, based on average incremental tariffs For Armgasprom this will actually be our final suggested income statement For Transgas and Haygas additional changes will need to be made For the Pipeline Company that change will be the introduction of commodity and demand charges, and for the Distribution Company the change will include the notion of differential tariffs to reflect differences in delivery costs to different classes of customers

Armgasprom

The Armgasprom Proforma Income Statement is shown in Table 6 The data used in constructing that Table come from the Armgasprom Column in Schedule F-2 and from Column 6 in Table B-2 (Appendix B) Line 1 of Armgasprom's Proforma Income Statement Operating Income, was obtained by multiplying Armgasprom's overall tariff ($70 571, Line 78 in Schedule F-2) with the annual sales volume of 1 672 500 Thousand Standard Cubic Meters and converting to Armenian drams using an exchange rate of 500 to 1 Note that minor differences here and elsewhere result from rounding errors since some of the variables used in our calculations were internally generated by the computer at great accuracy, and others were hand-entered into the equations at differing levels of precision

The line item Gas Purchased for Resale on Line 2 of the Proforma Income Statement reflects the tariff and VAT of $66 00 per MCM at the Armenian border times the import volume, again converted into Armenian drams Since Armgasprom does not physically transmit or distribute natural gas, its technological losses are zero, and the Company's Total Gas Supply Expense, Line 4 in Table 6 is equal to the cost of its Gas Purchased for Resale

Lines 5 through 16 in Table 6 reflect our best judgment of what Armgasprom's administrative and general expenses would be if operations were conducted in accordance with Western standards These lines are exact reproductions of Lines 1 through 10 in Column 6 of Table B-2 Appendix B where they are explained in some detail

Depreciation Expenses and Taxes Other Than Profit Taxes, shown on Lines 17 through 22 in the Armgasprom Proforma Income Statement are exact reproductions from Schedule F-2, except for the item labeled Value Added Taxes on Line 21 which comes from Line 67 of Schedule F-2 Gross Operating Income Line 24, simply is the difference between Operating Income on Line 1 and Total Operating Expenses, Line 23

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Interest payments are not considered part of operating expenses Hence they are listed separately on Lines 25 through 27 of Table 6 Deducting these Interest Expenses from Gross Operating Income yields a Gross Profit of 112 200 thousand drams (Line 30) The 25% profit tax now in place in Armenia is then applied to the Gross Profit to yield a Net Profit of 84 150 million drams

We have looked into the possibility of introducing the concept of commodity and demand charges at this stage of natural gas operations However we advise against it here There are no physical transactions at the level of Armgasprom, and no capacity considerations Hence demand (or capacity) charges seem out of place Instead our suggestion for Armgasprom is that its relatively modest operational costs be charged out exclusively through commodity charges which under the stipulated scenario, come out to be $4 57 per MCM, from Operating Income (Line 1) minus Gas Purchased for Resale (Line 2), divided by Total Deliveries (Line 31)

Transgas

The Transgas Proforma Income Statement is shown in Table 7 This Table has a specific line item reflecting technological losses in natural gas transmission These losses high at 3 8% by international standards, are listed on Line 3 where they are added to expenses incurred in purchasing gas for resale, to yield the Total Gas Supply Expense, Line 4

The individual line items on Lines 5 through 24 in Table 7 are accounts and subtotals reflective of those that the US Federal Energy Commission has established for monitoring costs of transmission companies These accounts are totaled and shown as Total Transmission Expenses on Line 25 Again as shown in connection with the Armgasprom Company adding the Total Gas Supply Expense Depreciation Expenses and Taxes Other Than Profit Taxes to Total Transmission Expenses yields Total Operating Expenses Line 32 That subtotal deducted from Operating Income (Line 1) yields the Pipeline Company's Gross Operating Income of 16 479,033 thousand drams Since no interest charges are incurred by Transgas, the Gross Operating Income is equal to the Company's Gross Profit which is then subjected to the 25% profit tax for its Net Profit of 12,359 275 thousand drams Line 39

Like most pipelines the Transgas Pipeline system lends itself to the application of demand and commodity charges The Demand Charge is a monthly charge imposed by the pipeline for the duration of the tariff cycle, generally one year This monthly charge obligates the pipeline company to set aside and hold in reserve a stated delivery capacity nominated by the customer and reflecting that customer's average year-around purchases and his peak purchases for three successive days The Commodity Charge, by contrast, is a variable charge based on actual monthly sales volumes

The principal advantages of applying demand and commodity charges are listed below

1 Monthly revenue flows to the pipeline are levelized enabling the company to meet its regular monthly operating and maintenance expenses with less difficulty,
2 If import volumes rise unexpectedly during a given tariff period, the end-user is protected from the monopolistic assertion of the pipeline's market power since only variable cost increases are permitted to be passed through, causing average pipeline tariffs to decline automatically, and
3 If import volumes decline unexpectedly during a given tariff period the pipeline is protected from incurring heavy losses since only the revenues associated with Commodity Charges decline, and these are a small portion of the total revenue

The split between Demand and Commodity Charges is usually made so that variable costs are recovered through the Commodity Charge and fixed costs are recovered through the Demand Charge although variants from this standard do exist To establish the demand and commodity tariff

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components for Transgas its costs shown in the Proforma Income Statement in Table 7 are subdivided into variable and fixed costs in Table 8 (Line 3)

In the United States the principal variable costs in pipeline operations are for technological losses and fuel costs As mentioned fuel costs are a minor item in Armenia since Transgas does not use compressors on its line to move the gas Instead the gas is moved through the pipeline by compressors located outside the Country and the compression cost is included in the border sales price As can be seen in Table 8 about 95% of the Transgas variable costs are for technological losses (Line 3)

Line 36 in Table 8 shows the revenues that must be generated through the use of demand charges (Revenue Requirement for Fixed Costs) and commodity charges (Revenue Requirement for Variable Costs) applied to total deliveries of 1,608,945 MCM per year Given the Transgas load factor of approximately 50%, the monthly demand charge comes out to be $500 582 per MCM per day (from [Fixed Costs / 12] / Maximum Daily Deliveries * 1000 / 2), Line 43 in Table 7 Given the average load factor of 50%, the Maximum Daily Deliveries (Line 40) are equal to Total Deliveries of 1 608 945 MCM per year (Line 39) divided by 365 days per year times a factor of two to reflect the fact that during peak periods the delivery volume for three successive days has been running twice as high as the average daily volume The monthly demand charge of $500 582 per MCM per day multiplied by the Maximum Daily Deliveries of 8 816 MCM/Day (Line 40) yields a monthly fee of $4 4132 million That fee is shown in Table 9, Column 3, entitled "Demand Charge" As can be seen in Table 9 the Demand Charge is a fixed monthly charge that does not vary with monthly delivery volumes

The commodity charge of $2 9254 per MCM in Table 8 was derived by dividing Variable Costs (Line 42) by Total Deliveries (Line 39) and converting into dollars again at the current exchange rate of 500 drams per dollar That tariff times the monthly volumes listed in Table 9 yields the Monthly Commodity Charges levied by Transgas (Column 4 in Table 9) Summing the Monthly Demand Charges and Commodity Charges yields the Total Monthly Bills (Column 5) A few explanatory remarks are in order in connection with Table 9

This has been mentioned before, but it deserves repeating The tariffs listed in Tables 9 10 and 11 are incremental tariffs They reflect the cost of transmission services provided by Transgas Whether Transgas charges incremental or total tariffs are depends on the ownership of the gas being transmitted

If Transgas buys the gas, transmits it, and then sells it to Haygas the total base-case charge will be the incremental amounts shown in Table 9 plus the gas purchased for resale On an annual basis, that would be $57 665 million (Table 9) plus $118 030 * (1 000-0 038) million, or $171 210 million (Line 77, Schedule F-2) If Transgas does not take ownership in the gas it transmits, the pipeline company's annual charge will simply be the amount shown in Table 9, or $57 665 million

The trend in the international gas industry has been to work on an incremental tariff basis In the United States almost all of the gas being shipped through pipelines is what is called non-equity gas i e the pipeline does not take ownership and the billing is based on incremental tariffs as shown in Tables 9 through 11 As mentioned this procedure provides greater flexibility in the market and fosters competition since it enables third-party suppliers to negotiate directly with the distribution company or with large industrial consumers for potentially significant cost savings to the end-user

Shown in Column 2 of Table 9 are simulated monthly sales volumes based on the stipulated total annual volume of 1 608 billion cubic meters and the historical Transgas sales profile With demand and commodity tariffs fixed for the one-year billing period, and the principal portion of the pipeline's total revenue generated through the demand charge, the variation in monthly pipeline revenues is minimal and average unit revenues are low in the winter months when volumes are high For example, in January, when sales soar to 215 million cubic meters, the average revenue per MCM to the pipeline is at an all-time low of $23 45 Of course total revenues in January are high at $5 04 million but not anywhere near what they would be if the tariff did not contain a demand component That is shown in Column 7 where the same monthly sales profile is subjected to a commodity-only tariff designed to recover the same costs as the demand-commodity tariff discussed up to this point Under this commodity-only tariff system the incremental component of the pipeline's January invoice to Haygas is $7 7 million or some 50% above that of the demand-commodity system

The difference between commodity-only and commodity-demand tariffs is illustrated in Figure 3 The commodity-only graph in that Figure is subject to substantial seasonal swings while the demand and commodity graph reflects nearly even incremental monthly billings throughout the year The even allocation of pipeline charges under the demand-commodity method matches the large fixed costs that Transgas incurs month after month throughout the year

Table 10 and its companion Figure 4 illustrate how the demand-commodity tariff methodology works in protecting the consumer when sales volumes rise sharply Columns 1 through 7 in Table 10 duplicate Table 9 and the heavy lines in Figure 4 connected with solid points duplicate Figure 3 A sharp increase in sales volumes is introduced in Column 8 and the impact on total and average incremental pipeline revenues is calculated and listed in the rest of Figure 4 More specifically, it is assumed for purposes of illustration that the sales volumes in both the base case and the high-volume case are the same for the first three months of the tariff cycle, July through September A sudden 20% increase in sales volumes is then assumed to take place in October and to be maintained for the rest of the tariff cycle in the high-volume case If a commodity-only tariff were in place, such an increase in sales volume would dramatically raise the pipeline's incremental revenues from its earlier levels For example the January high of $7 7 million would rise to $9.2 million even though most of the pipeline's expenses would remain unchanged Since this is a cost-recovery tariff system, the demand-commodity tariff would also go up, but only in an amount sufficient to permit the pipeline to recover its increase in variable costs For example the volume increase in January would raise revenues to the pipelines by $1 54 million under the commodity-only system whereas under the demand-commodity tariff system the increase would only be $130,000 The difference between these two numbers ($1 41 million) would be a pure windfall to the pipeline, not matched by offsetting increases in operating expenses By disallowing the pipeline to recover this amount the system acts to protect the natural gas end-users

However the system works protectively on behalf of the pipeline in those cases where a sudden decline in sales volumes reduces revenues This is illustrated in Table 11 and Figure 5 which are in all respects the same as Table 10 and Figure 4, except that monthly sales volumes are now assumed to decline by 20% in October Again to be noted here is the violent downward swing under the commodity-only methodology That downward swing in revenues is nearly eliminated under the demand-commodity tariff system which permits the pipeline, in true cost recovery-fashion, to recover all of its fixed costs The only cost savings accruing to the pipeline from the reduction in sales are its variable costs and those cost savings are passed on to the consumers via reduced billings

In the final analysis it is clear that a demand-commodity methodology tempers violent revenue swings while permitting full-cost recovery The system will protect consumers from unwarranted increases in billings when sales volumes rise, and it will protect the pipeline from potential disaster when sales volumes decline That is why we recommend that the ERC accept and implement the demand-commodity tariff methodology

One point remains to be discussed as regards the pipeline tariffs we have covered to date, and that is the level of the natural gas pipeline tariff now and in the future As will be recalled, the ERC Resolution 14 stipulated that the incremental Transgas tariff have a maximum level of $2 746 per MCM for large customers The Resolution is silent as regards incremental tariffs for small customers, but its predecessor Resolution 7, permits the maximum tariff to small end-users to be substantially higher than that for large customers, $102 0 vs $79 1 per MCM Be this as it may our incremental cost-recovery tariff comes in at $35 84 per MCM or about six times higher than the large-consumer incremental tariff under Resolution 14 and perhaps three to four times higher than the implicit small consumer tariff

We believe that one of the reasons for the significant deterioration of the Armenian pipeline system is the relatively low tariff that kept the system starved for operating capital but other reasons exist as well These will be taken up in Chapter 4 as will be suggestions regarding ways to resolve the pipeline tariff problem both in the short and long run We believe that a pipeline tariff that will permit the Government of Armenia to move forward in rehabilitating its system can be found and we will have definite suggestions later on as regards a transition mechanism in getting from today's unacceptably low pipeline tariffs to solid cost-recovery tariffs sufficiently high to rehabilitate the pipeline system and to sustain it in good operating condition for the indefinite future

Haygas

A Haygas Proforma Income Statement is shown in Table 12 This Table is essentially a re-statement of Schedule F-2 As discussed in connection with the Transgas Proforma Income Statement the company's technological losses 1 68% for distribution operations are shown as a separate line item (Line 3) The distribution expenses, Lines 5 through 15, again reflect US FERC uniform accounting and reporting standards These distribution expenses include the cost adjustments as discussed in detail in Appendix B All of the above expenses, plus depreciation expenses (Line 16) various kinds of taxes other than income taxes (Line 21) and interest expenses, zero in the case at hand since interest payments are handled by Armgasprom, deducted from operating income yield Haygas net profits of 5,417,251 thousand drams for the period in question, Line 29

Schedule F-2 shows explicitly and Table 12 assumes that one uniform natural gas tariff is applied to all Haygas customers In a true cost-recovery system those customers that as a group, can have natural gas delivered to them at lower unit cost should be able to benefit from the savings in delivery costs by being accorded a lower gas tariff than other customers whose delivery costs run measurably higher Such tariff differentiation reflecting differences in delivery costs is routinely accepted in international practice

As regards Armenia the issue that needs to be addressed in conjunction with distribution tariffs is whether and how to apply different tariffs to different consumer classes The ERC has recently established a differential tariff system by formally recognizing the existence of two classes of customers each with its own tariff ERC Resolution 7 has created a class of small customers (residential customers and other end-users consuming less than 10,000 SCM per month) and a class of large customers (those using more than 10,000 SCM per month) The only new question for us to consider is whether these two classes of customers are enough to provide the tariff differentiation that will be needed

In the United States most regulatory agencies routinely treat residential customers as a separate class Based on that principle if the residential sector is to be treated as a separate class a second non-residential class of small end-users will be needed We have introduced such a non-residential class of small end-users in deference to Armenian practice For lack of a better term, we have called this the "General Service" class It generally encompasses what in the US would be called the "Small Commercial and Industrial Sector"

As regards the large-customer class referred to in ERC Resolution 7, Haygas has in effect established two sub-classes By far the largest of these accounting for nearly 70% of all of Armenia's natural gas consumption, is what we have called the "Large-Volume Service" class That class consists primarily of power plants We would have had no problem dealing with only one large-volume class but the establishment by Haygas of a second sub-class for district heating plants is not without merit We

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have named that second sub-class the "Special Contract Service' class It contains 13 customers and accounts for a little over 20% of total consumption The existence of this class will permit direct negotiations between Haygas and district heating plants or between third-party suppliers and district heating plants to facilitate the establishment of individual cost-recovery tariffs designed to meet interfuel competition in the broader energy sector

As mentioned, the difference in natural gas tariffs for different Haygas customer classes resides in differences in delivery costs These differences reflect variations in the size of the load the delivery location and pressure, and frequency of delivery The average tariff shown in our earlier Schedule F-2 assumes that all these factors are the same across all classes of consumers

The problem in allocating realistic cost differences to recognized customer classes is that all customers share a common central delivery plant Given the capital-intensive nature of retailing natural gas to end-users, the elimination of duplicate facilities through the use to the fullest extent possible, of a central plant distribution system raises the economic efficiency of the overall system and reduces the cost to all end-users The question, then is how to charge central-plant induced common costs to the different customer classes

The overall daily capacity of a given central facility depends on the delivery volumes during peak consumption For a given annual volume, if deliveries took place at even daily rates the central delivery daily capacity would need to be sized to handle 1/365 of the required annual volume If there are seasonal or other variations and if, during peak consumption periods say in mid-January consumption rates were twice the average rate, the central system would have to have twice the average daily capacity However, if one customer has a very high peak period while other customers have none, the surplus capacity needed to maintain deliveries for the system as a whole would have to be absorbed by the customer with the high peak rate That customer is said to have a low load factor, i e , he has a relatively low load for most of the year, compared to his peak consumption period The load factor of a given customer class, then, is an important tariff determinant

Part of any gas distribution system are the distribution mains including the interconnect grid and auxiliary equipment designed to permit multiple paths of flow from the supply source to individual customers The distribution mains and auxiliary equipment represent the largest amount of capital used in an overall distribution system These are jointly used rather than customer-specific facilities Jointly-used facilities are subject to economies of scale since the large flow of combined natural gas deliveries permits the use of larger line sizes which are subject to decreasing unit costs per volume delivered

Other cost characteristics for retail distribution of natural gas include a large component for customer related activities Among those are customer-specific facilities which serve to connect the customer receiving station to the supply point These include the meter the individual regulator at the meter the cost of installing and maintaining the meter and regulator, and the service line from the location of the meter to the distribution main Once customer-specific facilities are installed their costs do not vary with the number of units delivered

The meter and related equipment are themselves subject to economies of scale Large customers with significant volume throughputs require large meters which are of course more expensive to purchase and install, but on a per unit of throughput volume basis they are less expensive This economy of scale is yet another factor causing delivery unit costs for large customers to be lower than those for smaller customers

Listed in Table 13 are the allocations of the Haygas income and O&M expenses by customer class Except for minor discrepancies due to rounding Column 1 in Table 13 repeats the values shown in Table 12 Haygas Proforma Income Statement As was explained earlier these values are derived from Schedule F-2 and Table B-3 in Appendix B

Columns 2 through 5 in Table 13 list the incomes and expenses associated with individual classes of service The costs allocated to each customer class use six different factors A series of numbered notes listed in Table 13 is used to identify the allocation factors for each cost item

Listed below are the line items identified by Note (2) shown on Lines 5 12 16 18 and 29 that have been allocated on the basis of the appraised value of assets of each customer class

Distribution Operations Expenses
Distribution Maintenance Expenses
Depreciation Expenses
Property Taxes, and
Net Profit

The allocation factor used for Social Taxes, Line 19 Note (3), is based on the relative size of Total Operating and Maintenance Expenses as displayed on Line 15 The Value Added Tax Note (4) shown on Line 20, has been allocated on the basis of Total Revenue Requirements minus Gas Purchase Expenses The calculation method uses a VAT rate of 20% Listed below are the line items identified by Note (5), shown on Lines 6, 7 8, and 9, that have been allocated on the basis of the numbers of connected customers

Customer Accounts Operations Expenses
Uncollectible Accounts
Customer Service and Informational Expenses
Sales Expenses

The Net Profits Tax in Note (6) for each customer class follows from the 25% profit tax applied to Net Profits described above Finally, the allocations of Administrative and General Expenses Note (7) on Line 10, and of Administrative and General Maintenance Expenses, Note (7) on Line 13, are based on non-administrative Total Operations Expenses (Lines 11 minus 10) For more detail regarding individual customer class allocations in Table 13 see Appendix C Also described in Appendix C Table C-1, are allocation techniques used in constructing Table 13

As mentioned in our discussion of Schedule F-2 the combined natural gas tariff for the end-users of all customer classes is $128 10 per MCM, or about 25% higher than the residential tariff currently allowed under ERC rules However, broken down into individual customer class tariffs, a bleak picture emerges The large-volume end-user tariffs come out at $111 71 per MCM ($3 16/MCF) for the Special Contract Service Class (district heating plants), and at $115 91 per MCM ($3 28/MCF) for the Large Volume Service Class These numbers are more or less in line with US tariffs, even though the Armenian gas industry is delivering gas at something like 20% of design capacity It is in the small-volume end-user classes that real tariff problems emerge For the General Service Class roughly equivalent to small industrial and commercial users the tariff comes out to be $153 65 per MCM ($4 35/MCF), still largely in line with US tariffs For the residential sector however, the delivered price of natural gas comes out at $302 31 per MCM ($8 56/MCF), compared to the US average residential tariff of $223 80 per MCM ($6 34/MCF)

This high residential tariff is clearly not acceptable in Armenia Part of the reason for the high tariff is the fact that the residential distribution system is running at about 7 4% of maximum historical deliveries in 1990 This means that the system is carrying more than 90% of dead overhead just to function Another reason for the high unit price is the small volume use per customer Also, the rate form inherent in a straight-line volumetric rate does not allow for tariff variations reflecting cost

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differences between customers using gas for cooking only and those using gas for space heating There are a number of rate forms available that are sensitive to variations in costs One rate form would be a flat monthly charge with or without tariff differentials for cooking or space heating with no charge for actual deliveries One variant of this rate form has previously been used in Armenia without measurement of individual residential usage Needless to say that form is not compatible with a true cost-recovery tariff system

The introduction of a flat monthly rate would not resolve the residential tariff dilemma and it could violate the cost-recovery principle In Table 13 the total revenue requirement for the residential class is 15,115,729 thousand drams The total number of customers served is 44 500 (Table C-1 Appendix C) If the ERC adopted a monthly flat rate plan under these conditions each customer would have to pay 28,307 drams per month, or $56 61, again a totally unacceptable number

With the advent of individual metering for each customer, one option would be a straight-line unit price per MCM delivered If the Haygas Enterprises adopted such a straight-line rate plan, each customer would have to pay 151 drams per SCM delivered As was noted above, this price is almost thirty-five percent higher than the average residential price in the United States Why have the residential customer costs increased so much? Again we refer to our earlier comment regarding the distribution system which is carrying more than 90% of dead overhead just to function Furthermore, most of the cost to serve the residential customer does not vary with delivery volume Referring to Table 13 the cost of gas purchased for resale is only 35 percent of total costs in the residential sector

The usual practice in the United States today takes this problem into consideration US distribution companies have solved the residential tariff dilemma by separating residential costs into Customer Costs and Commodity Costs They typically recover Customer Costs through monthly Flat Rates and through Connection Charges for initiating or re-initiating service (if, for example the company disconnects for non-payment or if the customer requests a temporary discontinuance of service) US distribution companies recover Commodity Costs through a straight-line unit price per SCM delivered This approach requires the classification of overall residential costs into Customer Costs Capacity Costs, and Commodity Costs as shown in Table C-2 (Appendix C) That Table confirms that the two-part rate design will reduce the commodity component of the residential tariff to $121 43 per MCM (from the summation of the capacity and commodity cost components of $10 41 and $111 02) The remaining fixed customer costs would provide a monthly flat rate of $33 87

The advantage of such a two-part (fixed-variable) residential tariff is that it evens out monthly bills for customers subject to seasonal variations in gas usage and that it protects the customer who increases his consumption rates by passing through only the additional variable costs However, there is no getting around the fact that the residential distribution system is still subject to ninety percent under-utilization, so that the annual costs to the customer, with or without a fixed-variable rate system are still prohibitive

It usually is not prudent to recover excessive embedded fixed costs through large monthly charges to the connected customer who would respond by requesting disconnects at every opportunity As mentioned the Haygas Enterprise could reduce those monthly charges by collecting additional revenues through the imposition of a Customer Connect Fee They could establish such a connection fee for service initiation or for service re-establishment if the company disconnects service for any reason This Connect Fee also must be cost-based The costs would reflect the labor and travel expense for a worker at the customer's premises where he would have to test the customer facilities for leaks before opening the flow of gas into the customer's facilities The cost for such a typical service call in the United States is around $45 In Armenia the costs may be different depending on productivity, labor rates and transportation cost In the aggregate, this Connect Fee could be a significant source of revenues

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To avoid creating incentives for summer disconnects Haygas must set the Connect Fee to equal a multiple of the Customer Monthly Flat Fee A typical US Connect Fee would be 6 5 times the monthly fixed fee which would make it cheaper for the customer to remain connected in the summer or more precisely for a little more than half a year even if he consumes no gas during that period The alternative no Connect Fee will create an operational nightmare and expense with countless consumers disconnecting and reconnecting at will for example when they go on vacation At the present time most of the revenues generated through such a connection fee in Armenia would likely be a one-time fee resulting from the expected growth in the number of customers over the next few years

Another reason why a large monthly flat charge is imprudent is the large difference between average embedded cost and average marginal cost of service The growth in load from connecting additional residential customers can generate excessive revenues if the monthly flat rate is greater than the average marginal cost to serve these new customers For example the average monthly marginal cost per customer in the year 2000 was calculated to be $7.25 To avoid giving the Haygas Enterprise a windfall from this customer growth the ERC could set the monthly customer flat charge at $8 00 (4000 drams)

The revenue shortfall from reducing the monthly flat charge from $33 87 to $8 00 can be offset with the Customer Connect Fee If such a fee were introduced and set at, say, 6 5 months' worth of fixed monthly fees, or about $52, this would provide a revenue of 4,600,000 thousand drams from the new customers next year This amount if collected, would approximately equal the shortfall from reducing the Monthly Flat fee in the year 2000

INTERIM RESULTS

The tariffs obtained so far seem high and they are on an absolute scale It would be well to remember the assumptions they are based on These assumptions include a price at the border of $55 00 per MCM, plus 20% VAT, a recently revised depreciated asset base of $238 million a return on assets of 15 0% and a rate of depreciation of 3 3% per year These assumptions, coupled with a cost-recovery tariff reflecting US cost standards, yield the average rates summarized below

	Armgasprom	Transgas	Haygas
Purchase Price	$66 00	$70 57	$106 41
Incremental Tariff	$4 57	$35 84	$21 69
Sales Price	$70 57	$106 41	$128 10

If that were the end of our analysis i e , if residential consumption remained forever at 100 million SCM per year actual tariffs to be charged by the respective companies would be as listed below

Armgasprom — $70 57 per MCM delivered each billing period

Transgas — $500 per Month per MCM Contract Daily Demand
$2 925 per MCM delivered each billing period
Contract Daily Demand equals the maximum daily delivery that occurred in the 365-day period ending with each billing period

Haygas
Residential Customer — $121 43 per MCM delivered each billing period,
$33 87 Customer Flat Fee each monthly billing period and
No Connection Charge

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General Service Small Customer	$153 65 per MCM delivered each billing period
Large-Volume Customer	$115 91 per MCM delivered each billing period
Special Contract Customer	$111 71 per MCM delivered each billing period

These tariffs reflect at least two major concessions to full-cost recovery The first is the use of a low depreciation rate which is applied on a 30-year straight-line basis to the depreciated assets In reality the assets are mostly 15 years old and older, and the depreciation rate would ordinarily have been more like 6 7% on depreciated assets The second concession applies to the Operating Expense Standards where the cost standards for Armenian enterprises were based on depreciated asset values in Armenia and full asset values in the United States

Still the tariffs are high, and the residential tariffs in particular require additional review and concessions As mentioned, part of the residential tariff problem is the very low utilization rate of distribution company assets and of pipeline assets That, however, will change dramatically Chapter 4 will look at residential rates at annual volumes higher than the 100 million SCM per year used here In particular, a 500 million SCM case and a 1000 million SCM case will be considered, the first case thought to be obtainable within two years at most, and the second only one or two years after that

Knowing what the residential tariffs will be under these scenarios will permit an assessment of interim measures that may be needed to promote the rapid reintroduction of natural gas in the residential sector and to expand that sector with a view to establishing full cost recovery at self-supporting long-term tariffs

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Table 6

ARMGASPROM ENTERPRISE
PROFORMA INCOME STATEMENT
For the twelve-Month Period Ending June 30 1999
THOUSANDS OF ARMENIAN DRAMS

LINE	DESCRIPTION	PROFORMA INCOME STATEMENT
1	OPERATING INCOME	59 015 084
	GAS SUPPLY EXPENSE	
2	Gas Purchased for Resale	55 192 500
3	Gas Purchased for Technological Losses	0
4	Total Gas Supply Expense	55 192 500
	OPERATING EXPENSES	
5	Administrative and General Salaries	843 118
6	Office Supplies and Expenses	463 759
7	Property Insurance	10 608
8	Injuries and Damages	45 971
9	Employee Pensions and Benefits	410 806
10	Regulatory Expenses	49 699
11	Other Expense	0
12	Rents	129 486
13	Total Operating Expenses	1 953 447
14	Maintenance of General Plant	21 792
15	Total Maintenance Expenses	21 792
16	TOTAL ADMINISTRATIVE AND GENERAL EXPENSES	1 975 239
17	DEPRECIATION EXPENSE	18 681
	TAXES OTHER THAN PROFIT TAXES	
18	Custom Fees	140 000
19	Property Taxes	3 366
20	Social Taxes	36 000
21	Value Added Taxes	637 097
22	TOTAL OTHER TAXES	816 463
23	TOTAL OPERATING EXPENSES	58 002 884
24	GROSS OPERATING INCOME	1 012 200
	INTEREST EXPENSE	
25	Short Term Loans	100 000
26	Long Term Loans	800 000
27	Total Interest Expense	900 000
28	GROSS PROFIT	112 200
29	PROFIT TAX	28 050
30	NET PROFIT	84 150
31	TOTAL DELIVERIES 1000 SCM per year	1 672 500
32	APPRAISED VALUE	561 000
33	Working Capital	0
34	TOTAL INVESTED CAPITAL	561 000
	COST CLASSIFICATION	
35	Fixed Costs	3 822 584
36	Variable Costs	0
37	PEAK DAY DELIVERIES 1000 SCM per Day	
	TARIFF IN US DOLLARS	
	Monthly Contract Payment per 1000 SCM	
38	Contract Daily Demand	
39	Unit payment per 1000 SCM Delivered	$4 57
40	Gas Purchase Cost per 1000 SCM Delivered	$66 00
41	AVERAGE INCREMENTAL REVENUE PER 1000 SCM	

Note Do not Recommend Use of Demand Charge
Use $4 57 Commodity Charge

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Table 7

TRANSGAS ENTERPRISE
PROFORMA INCOME STATEMENT
For the twelve-Month Period Ending June 30 1999
THOUSANDS OF ARMENIAN DRAMS

LINE	DESCRIPTION	TRANSGAS PROFORMA
1	OPERATING INCOME	85 605 045
	GAS SUPPLY EXPENSE	
2	Gas Purchased for Resale	56 772,429
3	Gas Purchased for Technological Losses (3.8%)	2,242,570
4	Total Gas Supply Expense	59 014,999
	TRANSMISSION EXPENSES	
	Transmission Operations	
5	Operation Supervision and Engineering	296 475
6	System Control and Load Dispatching	116 153
7	Communication System Expenses	89 802
8	Compressor Station Labor and Expenses	378,857
9	Gas for Compressor Station Fuel	74 000
10	Other Fuel and Power for Compressor Stations	18,344
11	Mains Expenses	731 884
12	Measuring and Regulating Station Expenses	196,068
13	Transmission and Compression of Gas by Others	0
14	Other Expenses	36 134
15	Rents	30 429
16	Subtotal Transmission Operations	1 980 447
	Maintenance	
17	Maintenance Supervision and Engineering	30 116
18	Maintenance of Structures and Improvements	25 237
19	Maintenance of Mains	159 586
20	Maintenance of Compressor Station Equipment	83 158
21	Maintenance of Measuring and Regulating Station Equipment	62,186
22	Maintenance of Communication Equipment	19 686
23	Maintenance of Other Equipment	1 246
24	Subtotal Maintenance	381 214
25	TOTAL TRANSMISSION EXPENSES	2,361 661
26	DEPRECIATION EXPENSE	2,743 754
	TAXES OTHER THAN PROFIT TAXES	
27	Custom Fees	0
28	Property Taxes	494 370
29	Social Taxes	79 560
30	Value Added Taxes	4 431 669
31	TOTAL OTHER TAXES	5,005 599
32	TOTAL OPERATING EXPENSES	69 126 012
33	GROSS OPERATING INCOME	16 479 033
	INTEREST EXPENSE	
36	Short Term Loans	
37	Long Term Loans	
38	Total Interest Expense	0
34	GROSS PROFIT	16 479 033
35	PROFIT TAX	4 119 758
39	NET PROFIT	12,359 275
40	TOTAL PURCHASES MCM per Year	1 672 500
41	TOTAL DELIVERIES MCM per Year	1 608 945
42	APPRAISED VALUE	82,395 000
	COST CLASSIFICATION	
43	Fixed Costs	26 479 233
44	Variable Costs	2,353 383
		28,832,616
45	PEAK DAY DELIVERIES 1000 nCM per Day	22,040
	TARIFF IN US DOLLARS	
	Demand Charge	
	Monthly Contract Payment per 1000 SCM	
	Contract Daily Demand	$200 24
	Commodity Charge	
	Unit Payment per 1000 SCM Delivered	$2.83
	Gas Purchase Cost per 1000 SCM Delivered	70 571
	AVERAGE REVENUE PER 1000 SCM	35 840

Table 8

TRANSGAS ENTERPRISE
DEMAND AND COMMODITY CHARGES
For the twelve-Month Period Ending June 30 1999
THOUSANDS OF ARMENIAN DRAMS

	DESCRIPTION	FIXED COST	VARIABLE COST	TOTAL REVENUE REQUIREMENT
1	OPERATING INCOME			85 605 045
	GAS SUPPLY EXPENSE			
2	Gas Purchased for Resale			56 772 429
3	Gas Purchased for Technological Losses		2,242 570	2,242 570
4	Total Gas Supply Expense			59 014 999
	TRANSMISSION EXPENSES			
	Transmission Operations			
5	Operation Supervision and Engineering	296,475		296,475
6	System Control and Load Dispatching	116 153		116 153
7	Communication System Expenses	99,902		99,902
8	Compressor Station Labor and Expenses	378,957		378,957
9	Gas for Compressor Station Fuel		74 000	74 000
10	Other Fuel and Power for Compressor Stations		18,344	18 344
11	Mains Expenses	731,984		731,984
12	Measuring and Regulating Station Expenses	198,068		198 068
13	Transmission and Compression of Gas by Others	0		0
14	Other Expenses	36 134		36 134
15	Rents	30,429		30 429
16	Subtotal Transmission Operations	1,888 103	92,344	1 980 447
	Maintenance			
17	Maintenance Supervision and Engineering	30 116		30 116
18	Maintenance of Structures and Improvements	25,237		25,237
19	Maintenance of Mains	159,586		159,586
20	Maintenance of Compressor Station Equipment	83 158		83 158
21	Maintenance of Measuring and Regulating Station Equ	62 186		62 186
22	Maintenance of Communication Equipment	19 686		19 686
23	Maintenance of Other Equipment	1,246		1 246
24	Subtotal Maintenance	381,214		381 214
25	TOTAL TRANSMISSION EXPENSES	2,269,317	92 344	2 361 661
26	DEPRECIATION EXPENSE	2 743 754		2 743 754
	TAXES OTHER THAN PROFIT TAXES			
27	Custom Fees	0		0
28	Property Taxes	494,370		494,370
29	Social Taxes	79,560		79,560
30	Value Added Taxes	4,413,200	18,469	4,431 669
31	TOTAL OTHER TAXES	4,987 130	18 469	5 005,599
32	INCREMENTAL OPERATING EXPENSES	10,000,201	2,353,383	12,353,583
33	PROFIT BEFORE PROFIT TAX	16,479 000		0
34	PROFIT TAX	4 119 750		0
35	NET OPERATING INCOME	12 359,250		0
36	REVENUE REQUIREMENT	26,479,201	2,353,383	28,832 583
37	APPRAISED VALUE - Millions of Armenian Drams			82,395
38	TOTAL PURCHASES MCM per Year			1 672 500
39	TOTAL DELIVERIES - MCM per Year			1 608 945
40	MAXIMUM DAILY DELIVERIES - MCM per Day			8,816
	COST CLASSIFICATION			
41	Fixed Costs			26,479,201
42	Variable Costs			2,353 383
	TARIFF IN US DOLLARS			
	DEMAND CHARGE			
	Monthly Contract Payment per MCM			
43	Contract Daily Demand (Max Deliveries)			500.582
	COMMODITY CHARGE			
44	Unit Payment per MCM			$2.9254
45	Gas Purchase Cost per MCM Delivered			$70 571
46	INCREMENTAL REVENUE PER MCM			$35 840

Table 9

TRANSGAS ENTERPRISE
MONTHLY BILLINGS, BASE CASE, US $
For the Twelve-Month Period Ending June 30, 1999

Demand Rate $500/Mo/MCM Commodity Rate $2 925/MCM

	Delivery Volumes to Haygas	Using Demand and Commodity Charges				Total Bill No D&C Charges
		Demand Charge	Commodity Charge	Total Bill	Average Revenue per MCM	
Month	MCM	10^3 $US	10^3 $US	10^3 $US	$/MCM	10^3 $US
(1)	(2)	(3)	(4)	(5)	(6)	(7)
July	114 546	4 413 20	335 05	4 748 25	41 45	4 105 33
August	109 727	4 413 20	320 95	4 734 15	43 14	3 932 62
September	109 185	4 413 20	319 37	4 732 57	43 34	3 913 19
October	109 039	4 413 20	318 94	4 732 14	43 40	3 907 96
November	126 395	4 413 20	369 71	4 782 91	37 84	4 530 00
December	175 584	4 413 20	513 58	4 926 78	28 06	6 292 93
January	215 052	4 413 20	629 03	5 042 23	23 45	7 707 46
February	147 570	4 413 20	431 64	4 844 84	32 83	5 288 91
March	154 244	4 413 20	451 16	4 864 37	31 54	5 528 10
April	125 248	4 413 20	366 35	4 779 55	38 16	4 488 89
May	113 169	4 413 20	331 02	4 744 22	41 92	4 055 98
June	109 185	4 413 20	319 37	4 732 57	43 34	3 913 19
Totals/Averages	1,608,944	52,958 42	4 706 16	57,664 58	35 840	57 664 55

Figure 3

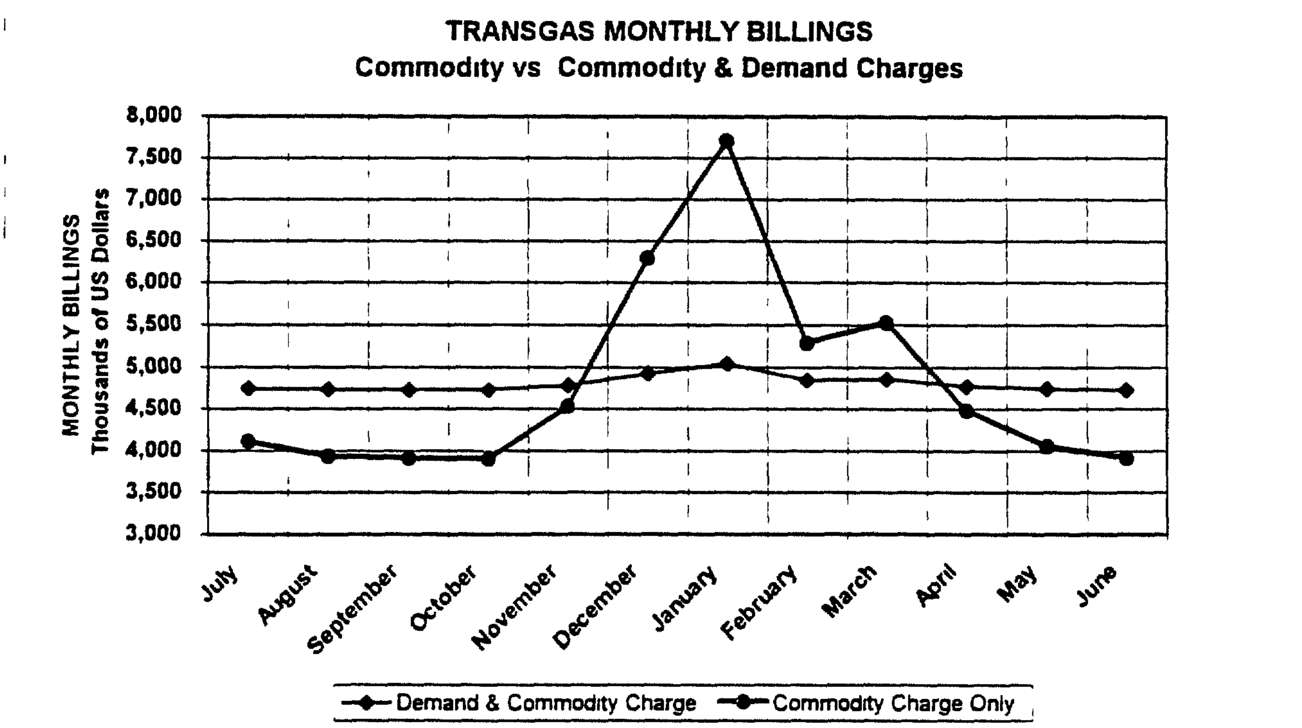

Table 10

TRANSGAS ENTERPRISE
MONTHLY BILLINGS HIGH VOLUMES US $
For the Twelve Month Period Ending June 30 1999

	Base Case Delivery Volumes						High Delivery Volumes			
		Using Demand and Commodity Charges								
	Delivery Volumes to Haygas	Demand Charge	Commodity Charge	Total Bill	Average Revenue per MCM	Total Bill, No D&C Charges	Delivery Volumes to Haygas	Total Bill With D&C Charges	Average Revenue per MCM	Total Bill No D&C Charges
Month	MCM	10^3 $US	10^3 $US	10^3 $US	$/MCM	10^3 $US	MCM	10^3 $US	$/MCM	10^3 $US
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
July	114 546	4 413 20	335 05	4 748 25	41 45	4 105 33	114 546	4 748 25	41 45	4 105 33
August	109 727	4 413 20	320 95	4 734 15	43 14	3 932 62	109 727	4 734 15	43 14	3 932 62
September	109 185	4 413 20	319 37	4 732 57	43 34	3 913 19	109 185	4 732 57	43 34	3 913 19
October	109 039	4 413 20	318.94	4 732 14	43 40	3 907 96	130 847	4 795 93	36 65	4 689 55
November	126 395	4 413 20	369 71	4 782.91	37 84	4 530 00	151 674	4 856 85	32 02	5 436 00
December	175 584	4 413 20	513 58	4 926 78	28 06	6 292 93	210 701	5 029 50	23 87	7 551 52
January	215 052	4 413 20	629 03	5 042 23	23 45	7 707 46	258 062	5 168 03	20 03	9 248 96
February	147 570	4 413 20	431 64	4 844 84	32 83	5 288 91	177 084	4 931 17	27 85	6 346 69
March	154 244	4 413 20	451 16	4 864 37	31 54	5 528 10	185 093	4 954 60	26 77	6 633 73
April	125 248	4 413 20	366 35	4 779 55	38 16	4 488 89	150 298	4 852 82	32 29	5 386 67
May	113 169	4 413 20	331 02	4 744 22	41 92	4 055 98	135 803	4 810 42	35 42	4 867 17
June	109 185	4 413 20	319 37	4 732 57	43 34	3 913 19	131 022	4 796 44	36 61	4 695 83
Totals/Averages	1 608 944	52.958 42	4 706 16	57 864 58	35 840	57 864 55	1 864 041	58 410 74	31 34	66 807 24

Figure 4

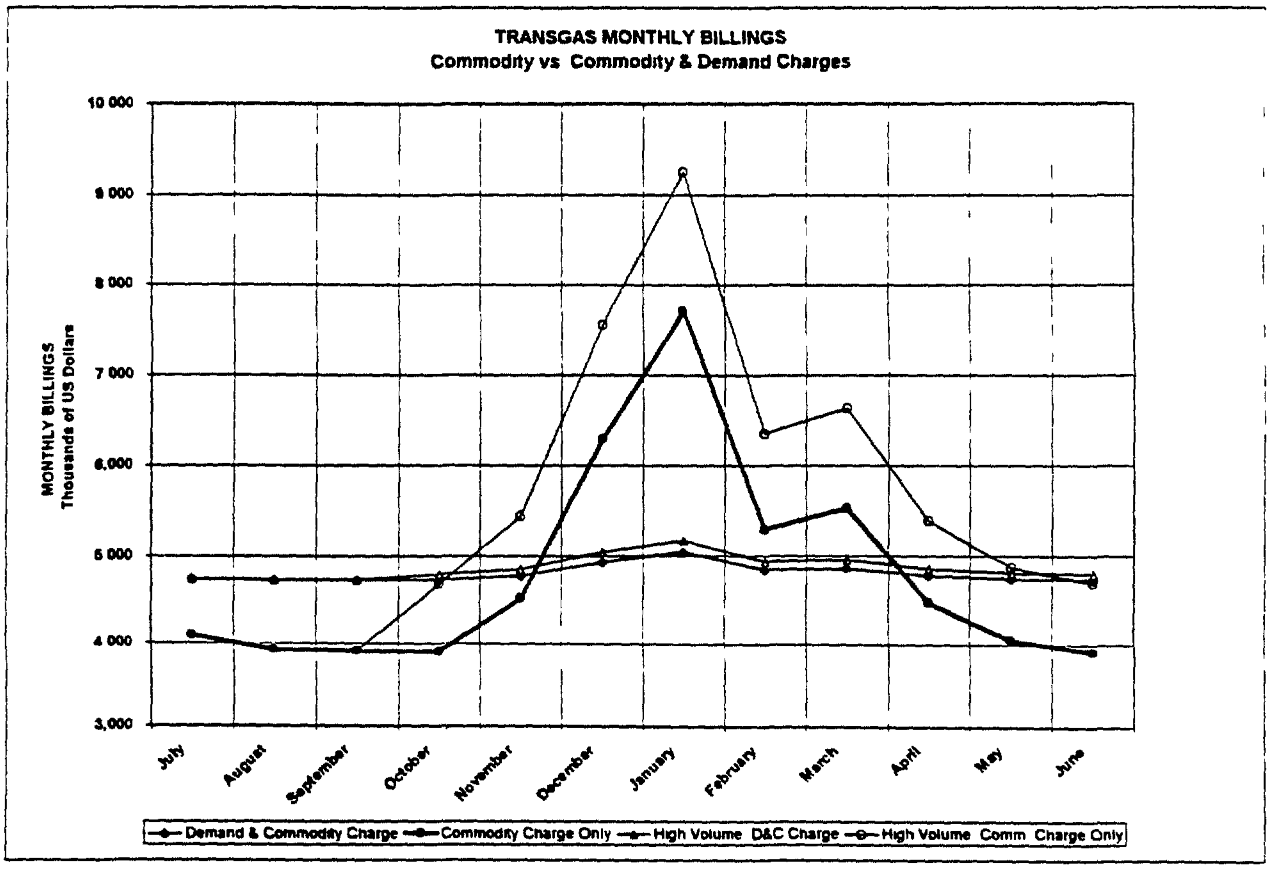

Table 11

TRANSGAS ENTERPRISE
MONTHLY BILLINGS, LOW VOLUMES US $
For the Twelve-Month Period Ending June 30 1999

	Base Case Delivery Volumes						Low Delivery Volumes			
		Using Demand and Commodity Charges								
	Delivery Volumes to Haygas	Demand Charge	Commodity Charge	Total Bill	Average Revenue per MCM	Total Bill No D&C Charges	Delivery Volumes to Haygas	Total Bill With D&C Charges	Average Revenue pe MCM	Total Bill No D&C Charges
Month	MCM	10^3 $US	10^3 $US	10^3 $US	$/MCM	10^3 $US	MCM	10^3 $US	$/MCM	10^3 $US
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
July	114 546	4 413 20	335 05	4 748 25	41 45	4 105.33	114 546	4 748 25	41 45	4 105 33
August	109 727	4 413 20	320 95	4 734 15	43 14	3 932 62	109 727	4 734 15	43 14	3 932 62
September	109 185	4 413 20	319 37	4 732 57	43 34	3 913 19	109 185	4 732 57	43 34	3 913 19
October	109 039	4 413 20	318 94	4 732 14	43 40	3 907 96	87 231	4 668 35	53 52	3 126 37
November	126 395	4 413 20	369 71	4 782 91	37 84	4 530 00	101 116	4 708 97	46 57	3 624 00
December	175 584	4 413 20	513 58	4 926 78	28 06	6 292 93	140 467	4 824 07	34 34	5 034 34
January	215 052	4 413 20	629 03	5 042 23	23 45	7 707 46	172 042	4 916 42	28 58	6 165 97
February	147 570	4 413 20	431 64	4 844 84	32 83	5 288 91	118 056	4 758 52	40 31	4 231 13
March	154 244	4 413 20	451 16	4 864 37	31 54	5 528 10	123,395	4 774 13	38 69	4 422 48
April	125 248	4 413 20	366 35	4 779 55	38 16	4 488 89	100 198	4 706 28	46 97	3 591 11
May	113 169	4 413 20	331 02	4 744 22	41 92	4 055 98	90 535	4 678 02	51 67	3 244 78
June	109 185	4 413 20	319.37	4 732 57	43 34	3 913 19	87 348	4 668 69	53 45	3 130 55
Totals/Averages	1 608 944	52 958 42	4 706 16	57 664 58	35 840	57 664 55	1 353 847	56 918 42	42 042	48 521 87

Figure 5

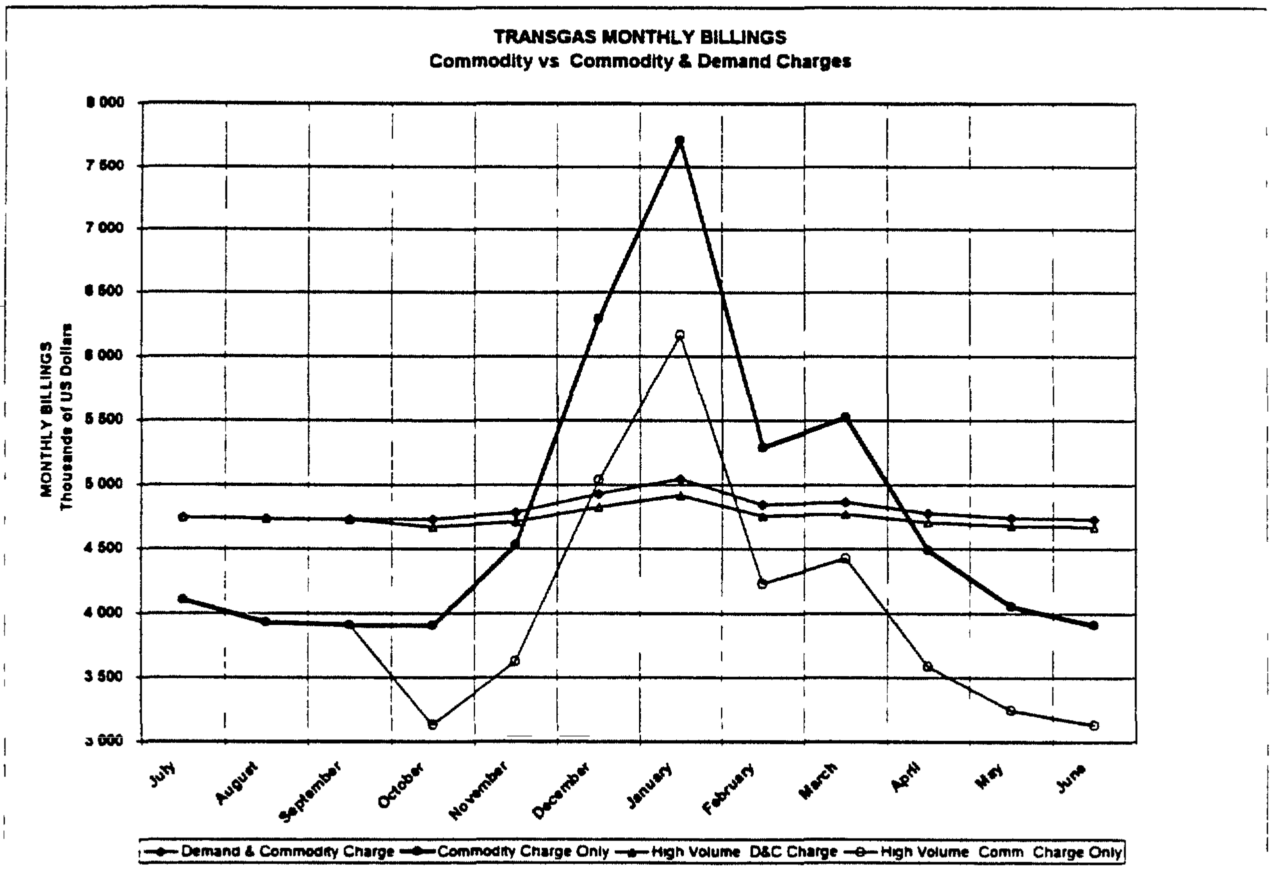

Table 12

HAYGAS ENTERPRISE
INCOME STATEMENT
For the twelve-Month Period Ending June 30, 1999
THOUSANDS OF ARMENIAN DRAMS

LINE	DESCRIPTION	HAYGAS PROFORMA INCOME STMT
1	OPERATING INCOME	101 319 118
	GAS SUPPLY EXPENSE	
2	Gas Purchased for Resale	84 166 931
3	Gas Purchased for Technological Losses	1 438,166
4	Total Gas Supply Expense	85,605 097
	DISTRIBUTION EXPENSES	
	Distribution Operations	
5	Distribution Operation Expenses	1,618 472
6	Customer Accounts Operation Expenses	464,426
7	Provision for Bad Debt	80,971
8	Customer Service and Informational Expenses	114,408
9	Sales Expenses	74,180
10	Administrative and General Expenses	1 240,695
11	Subtotal Distribution Operations	3,593,153
	Maintenance	
12	Distribution Maintenance Expenses	697 848
13	Administrative and General Maintenance Expenses	17 696
14	Subtotal Maintenance	715,544
15	TOTAL DISTRIBUTION EXPENSES	4,308 697
16	DEPRECIATION EXPENSE	1,202,630
	TAXES OTHER THAN PROFIT TAXES	
17	Custom Fees	0
18	Property Taxes	216,690
19	Social Taxes	144,000
20	Value Added Taxes	2,619,004
21	TOTAL OTHER TAXES	2,979,694
22	TOTAL OPERATING EXPENSES	94 096 117
23	GROSS OPERATING INCOME	7 223 001
	INTEREST EXPENSE	
24	Short-Term Loans	
25	Long-Term Loans	
26	Total Interest Expense	0
27	GROSS PROFIT	7,223,001
28	PROFIT TAX	1,805,750
29	NET PROFIT	5,417,251

Table 13

HAYGAS ENTERPRISE
INCOME STATEMENT BY CLASS OF SERVICE
For the Twelve-Month Period Ending June 30, 1999
Thousands of Armenian Drams

DESCRIPTION	Note	Total Amount	Residential Service	General Service	Large Volume Service	Special Contract Service	Line
COLUMN NUMBER		1	2	3	4	5	
OPERATING REVENUES		101,318 697	15 115 729	4 168 107	63 197 329	18,837,532	1
GAS SUPPLY EXPENSE							
Gas Purchased for Resale		84 166,579	5,320,550	2,886 608	58 016,251	17,943 170	2
Gas Purchased for Technological Losses		1,438 160	90,913	49,324	991,327	306,596	3
TOTAL GAS SUPPLY EXPENSE		85 604 738	5,411,463	2,935,931	59 007 578	18,249 766	4
OPERATING AND MAINTENANCE EXPENSES							
Distribution Operation Expenses	(2)	1 618,471	953,857	124,976	473,235	66,403	5
Customer Accounts Operation Expenses	(5)	464,426	421 019	42 102	1 183	123	6
Uncollectible Accounts	(5)	80,971	73,403	7,340	206	21	7
Customer Service an Informational Expenses	(5)	114,409	103 716	10,372	291	30	8
Sale Expenses	(5)	74 181	67,248	6 725	189	20	9
Administrative and General Expenses	(7)	1,240,695	853,994	101,005	250,572	35 124	10
Total Operations Expenses		3,593 153	2,473,236	292,519	725 676	101 721	11
Distribution Maintenance Expenses	(2)	697,849	411,282	53,887	204 049	28 632	12
Administrative and General Maintenance Expenses	(7)	17,696	12 180	1,441	3 574	501	13
Total Maintenance Expenses		715,545	423,463	55,327	207 623	29 133	14
TOTAL OPERATING AND MAINTENANCE EXPENSES		4,308 698	2 896 699	347,847	933,299	130,854	15
DEPRECIATION EXPENSES	(2)	1,202 630	708 778	92,865	351 645	49 342	16
TAXES OTHER THAN INCOME							
Custom Taxes		0					17
Property Taxes	(2)	216 690	127 708	16 732	63,359	8,890	18
Social Taxes	(3)	144 000	96,810	11 625	31 192	4 373	19
Valued Added Taxes	(4)	2 618,993	1 617,378	205,363	698,292	97,961	20
TOTAL TAXES OTHER THAN INCOME		2 979 683	1,841,895	233 720	792,843	111,225	21
TOTAL EXPENSES BEFORE INCOME TAXES		94 095 749	10,858,835	3 610 363	61 085,364	18,541 187	22
GROSS OPERATING INCOME		7,222,948	4,256,894	557 744	2 111 965	296,345	23
PROFIT TAXES	(6)	1,805 737	1 064,223	139,436	527 991	74 086	24
NET OPERATING INCOME		5 417,211	3 192 670	418,308	1,583,974	222,259	25
INTEREST EXPENSES							
Short Term Loans		0					26
Long Term Loans		0					27
TOTAL INTEREST EXPENSES		0					28
NET PROFIT	(2)	5,417,211	3 192,670	418 308	1,583 974	222,259	29
TOTAL DELIVERIES — 1000 SCM per Year		1 581,915					30
APPRAISED VALUE — Millions of Armenian Drams		36 114 74	21,284.47	2 788 72	10,559 82	1,481 73	31
GAS PURCHASE COST US $ per 1000 SCM		$106.41					
AVERAGE REVENUE PER MCM		$128 10	$302.31	$153 65	$115.91	$111 71	32

Chapter

4

Tariff Suggestions

Future Tariffs and Remedial Transition Policies

Introduction

Increases in natural gas tariffs, and especially in residential tariffs are subject to substantial economic and political vulnerabilities Given the currently low residential consumption rate of 100 million SCM per year, the partially restricted use of residential natural gas for cooking and the resulting rate of utilization of less than 10 percent of the residential distribution capacity, cost-recovery tariffs will necessarily be high In view of the current average purchasing power of the citizens of Armenia, the calculated equivalent commodity tariff of $302 31 per MCM, some 35% higher than in the United States is politically and economically unacceptable However the 100 million SCM scenario only reflects a transitory situation We used that volume because the ERC wanted to know what a cost-recovery tariff would amount to under the consumption volumes currently in existence The answer, to put it bluntly, is that Armenia could not have a residential gas sector without heavy subsidies or tax concessions from the State if 100 million SCM were its permanent residential consumption volume incapable of future growth

Fortunately, rapid growth is not just a possibility it is a process that is very much under way As mentioned in Chapter 1, at 83 3% Armenia had the highest market penetration in gaseous fuels of all former Soviet Republics Its peak residential consumption in 1990 was 1355 million SCM, and current projections anticipate a 1999 residential consumption rate of 510 million SCM (ERC) or 810 million SCM (gas industry) The natural gas consumption outlook is equally bullish further into the future The gas industry anticipates crossing the 1000 million SCM barrier in the year 2000 with the ERC not far behind, for the year 2001

If these rates are achievable, and they could be with some temporary assistance from the State the question to resolve is what the natural gas tariffs will be at the higher sales rates and whether these tariffs will be sustainable in the long run The first part of this chapter will analyze this issue, using a 500 and 1000 million SCM residential consumption rate as its base scenario

Future Tariffs

We used Schedule F-2 as the point of departure for our average gas tariff calculations at the higher volumes Schedule F-2, it will be remembered was the Schedule that incorporates all changes from Armenia's current tariff methodology to that suggested here at the current residential consumption rate of 100 million SCM To arrive at average tariffs for each gas company at residential consumption rates of 500 million and 1000 million SCM per year, we derived Schedules F-3 and F-4, respectively These are shown in Appendix D Since the derivation of the F-schedules has been covered in some detail, notably in Appendix B, there is no need here to reiterate the procedure Suffice it to list in summary fashion the average tariffs that emerged from these two schedules

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TARIFF CHANGES WITH RISING THROUGH-PUT VOLUMES

	Armgasprom	Transgas	Haygas
100 Million SCM			
Purchase Price	$66 00	$70 57	$106 41
Incremental Tariff	$4 57	$35 84	$21 69
Sales Price	$70 57	$106 41	$128 10
500 Million SCM			
Purchase Price	$66 00	$69 47	$97 32
Incremental Tariff	$3 47	$27 85	$24 42
Sales Price	$69 47	$97 32	$121 74
1000 Million SCM			
Purchase Price	$66 00	$68 80	$91 77
Incremental Tariff	$2 80	$22 97	$26 91
Sales Price	$68 80	$91 77	$118 68

As shown in the preceding Table, the average tariffs do come down as the system's through-put volume rises This is particularly true for the incremental tariffs of Armgasprom and Transgas For Armgasprom, the declining tariffs shown above need no further discussion For Transgas the question arises how the declining incremental tariff translates itself into equivalent demand and commodity rates We have previously discussed the technique in making this transformation, so there is no need to repeat the story here Suffice it to point out that the calculations have been made and the results are posted in the following Table

TRANSGAS DEMAND AND COMMODITY TARIFFS VS VOLUME

	Incremental Tariff	Demand Component	Commodity Component
100 Million SCM	$35 84	$500 60	$2 93
500 Million SCM	$27 85	$349 06	$2 85
1000 Million SCM	$22 97	$263 44	$2 80

The story is different for Haygas, where incremental tariffs rise with increasing volumes Overall, though tariffs to the end-users decline as volumes go up since the combined reduction in Armgasprom and Transgas incremental tariffs are larger than the increase in Haygas incremental tariffs

The reason for this counterintuitive behavior of Haygas incremental tariffs is that Haygas operating costs rise significantly with increasing residential consumption rates, given the dramatic increase in its number of customers That number rises from 44,500 in the base case to 222,500 for the 500 million SCM case and to 445,000 in the 1000 million SCM case Armgasprom and Transgas do not have anywhere near that kind of an increase in operating costs, so that the savings that result from the more efficient use of central facilities essentially accrue to these two companies which, in a cost-recovery system are then passed on to Haygas

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Within Haygas the tanffs to end-users decline as follows (Tables D-1 and D-2 in Appendix D)

END-USER TARIFFS, $/MCM

Residential Volume Million SCM	Overall Haygas Tanff	Residential Tanff	General Service Tanff	Large-Vol Service Tanff	Special Contract Tanff
100	$128 10	$302 10	$153 65	$115 91	$111 71
500	$121 75	$177 44	$119 24	$104 25	$101 38
1000	$118 68	$152 64	$108 61	$97 29	$95 13

To be noted in the preceding Table is the fact that, in spite of significant offsetting cost increases the tanffs in the residential sector decline the most in absolute and relative terms by nearly $150 per MCM or 50% Under the volume projections mentioned earlier this decline from $302 10 per MCM ($8 56/MCF) to $152 64 per MCM ($4 32/MCF, or about two thirds of the US residential rate of $6 34/SFC) would occur no later than in 2001/2002

We have one more step to go in our analysis, and that is the separation of residential tanffs into fixed and vanable components This procedure has been discussed in connection with Table 8 Chapter 3 so we will simply list the result of these calculations here Additional detail is presented in Tables D-3 and D-4 Appendix D

PROJECTED RESIDENTIAL TARIFFS

Volume Million SCM	Projected For Year ERC/Gas Industry	Average Tanff $/MCM	Fixed Monthly Fee	Commodity Rate $/MCM
100	Now	302 10	$33 87	$121 43
500	1999/1999	177 44	$12 58	$110 29
1000	2001/2000	152 64	$9 34	$102 79

The tanff to focus on in the preceding table is the tanff corresponding to the 1000 million SCM annual residential consumption rate That tanff has a fixed monthly component of $9 34 and a vanable unit rate of $102 79 per MCM of natural gas consumed For an average residential consumer using 2 247 MCM per year or 0 187 MCM per month, the monthly bill at that consumption rate comes out at $9 34 fixed monthly fee plus a $19.25 commodity charge, for a total average monthly bill of $28 59 Two comments are in order regarding the amount of the projected monthly bills

First an average tanff of $152 64 is high by Armenian standards, about 50% higher than the current maximum residential rate This presents a political dilemma for Armenia where energy prices have been below cost recovery for a long time and where incomes are still very low As a gauge of the reasonableness of this tanff one might wonder how the calculated tanff compares with residential tanffs in the rest of the world Listed in Table 14 are residential tanffs for many countnes, collected by the International Energy Agency in Pans, the energy statistical branch of the Organization for Economic Co-operation and Development (OECD) As that Table shows, the average residential tanff for the 24 listed countnes is $343 per MCM, more than three times the currently allowable maximum tanff and more than twice the tanff we are suggesting here In fact there are only four countnes with tanffs lower than the one we suggested, and three of those (the Czech Republic the Slovak Republic,

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Table 14

INTERNATIONAL NATURAL GAS TARIFFS
RESIDENTIAL SECTOR

Country	$/10^7 kc	$/10^6 Btu	$/MCF	$/MCM
Australia	332 8	8 39	8 61	304
Austria	463 8	11 69	12 00	424
Belgium	451 8	11 39	11 69	413
Canada	169 7	4 28	4 39	155
Czech Republic	131 6	3 32	3 41	120
Denmark	739 4	18 63	19 14	675
Finland	181 4	4 57	4 69	166
France	470 4	11 85	12 17	430
Germany	438 9	11 06	11 36	401
Hungary	136 3	3 43	3 53	125
Ireland	472 8	11 91	12 24	432
Japan	1294 1	32 61	33 49	1182
Luxembourg	319 4	8 05	8 27	292
Netherlands	363 4	9 16	9 40	332
New Zealand	415 5	10 47	10 75	380
Poland	236 1	5 95	6 11	216
Spain	613 4	15 46	15 88	560
Switzerland	505 7	12 74	13 09	462
Turkey	209 3	5 27	5 42	191
United Kingdom	325 7	8 21	8 43	298
United States	242 2	6 10	6 27	221
Chinese Taipei	411 0	10 36	10 64	375
Slovak Republic	77 9	1 96	2 02	71
Venezuela	10 9	0 27	0 28	10
	Sum		233 27	8235
	Average		9 72	343
Armenia				
Resolution 14				**102**
Hagler Model				**152 64**

Conversions used

US \$ per 10^7 Kilocalories times 0 0252 = US \$ per Million Btu

US \$ per Million Btu times 1 027 = US \$ per MCF

US \$ per MCF times 35 3 = US \$ per MCM

Source

Energy Prices and Taxes Third Quarter 1997 Part II Section D Table 14 and Section B Table 14 Paris International Energy Agency 1998

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and Hungary) are former centrally regulated economies Long-term habits are hard to break The fifth country with a residential tariff lower than our suggestion is the totally hopeless case of Venezuela where the tariff does not even come near recovery of production costs let alone transportation and distribution costs

The tariffs listed in Table 14 are not the whole story Missing are wellhead or import prices and tax treatments The severity of the Armenian tariff squeeze is perhaps worse than indicated by the raw numbers in Table 14 if one considers the elevated taxation of natural gas as it progresses from the Georgia border to the end-user That has been discussed elsewhere and needs no repetition here

Second we looked at residential natural gas consumption rates in the United States and found that the average consumption volume provided to us for Armenia appears to be high In the United States where the floor space of residential dwellings is generally larger than in Armenia and where more than 70% of the gas-fueled housing units are single-family structures, the average consumption in households using natural gas is 2 5 MCM per year for the nation at large This includes cooking water heating and space heating For the US Midwest Census Region, which is more nearly comparable climatically to Armenia, total gas consumption runs at 3.2 MCM per year roughly the same as in Armenia if one allows for the larger floor space in the States For space heating alone, the natural gas consumption in the Midwest Census Region is 2 6 MCM per year, and for cooking it is 0 21 MCM per year With that kind of residential consumption, the average monthly bill in Armenia for gas used only for cooking should come to around $11 14, provided that the relatively lower residential gas consumption is offset by increases in gas consumption in other sectors of the Armenian economy The average monthly bill of $28 59 mentioned earlier still holds but it applies to cooking water heating and space heating

We recommend that the average tariff of $152 64, as listed above be adopted as the final long-term tariff, with the fixed fee of $9 34 per Month and the commodity rate of $102 79 per MCM This tariff, of course, will vary under our methodology depending on import volumes and prices and a number of other variables These and other recommendations are summarized in the section that follows

OUR RECOMMENDATIONS

We recommend that the 1000 million residential volume standard be adopted and that the tariff calculated under this standard be accepted The tariffs so calculated are lower than true cost-recovery tariffs at current consumption rates, but they are higher than tariffs currently in force in Armenia However, the introduction of these tariffs and adherence to a Western tariff methodology will yield an extraordinary windfall to the State that we believe could be used to provide interim financial support This will be discussed in some more detail later For now here are our recommended tariffs

Armgasprom Gas Tariff

Commodity Charge at $68 80 per MCM delivered each billing period

Transgas Tariffs

Sales for Resale

- Demand Charge @ $263 per Month per MCM Contract Demand
- Commodity Charge @ $71 60 per MCM delivered each billing period

Transport Service

- Demand Charge @ $263 per Month per MCM Contract Demand plus
- Commodity Charge @ $2 80 per MCM delivered each billing period
- Contract Daily Demand equals the maximum daily delivery that occurred in the 365-day period ending with each billing period

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Haygas Tariffs

Residential Service

Fixed Monthly Fee @ $9.34 per Month each billing period
Commodity Charge @ $102.79 per MCM delivered each billing period
Service Charge @ $60.00 each time service is reconnected

General Service

Commodity Charge @ $108.61 per MCM delivered each billing period
or Monthly Minimum Bill of $28.02

Large Volume Service

Available to customers using more than 10,000 SCM/Month
Demand Charge @ $263 per Month per MCM Contract Demand, plus
Commodity Charge @ $78.26 per MCM delivered each billing period
Contract Daily Demand equals the maximum daily delivery that
occurred in the 365-day period ending with each billing period

Special Contract Service

Available to Customers using more than 10,000 SCM per Month
Subject to special terms of service by special contract
Customer must have the capability to switch to alternate fuel within
30 Minutes upon request by Haygas
Commodity Charge @ $95.13 per MCM delivered each billing period

Note that these tariffs reflect gas import prices as of February 1998. These prices do vary and, in fact, they have come down to $53.00 per MCM (from $55.00) since we began this report. At this stage, it would not appear to be very practical to make new model runs every time there is a change in one of the parameters. We suggest that the model be automated before any extensive excursions are undertaken. In the meantime, reducing the various end-user tariffs in the top table of Page 31 by $2.40 per MCM (price reduction and VAT reduction) will give a fair idea of the overall magnitude of the resulting tariffs.

The tariffs listed above have been designed to limit the competitive pressure for switches between customer classes. For example, the general service rate ($108.61) is lower than the average revenue from individual residential customers ($152.54). This price differential would encourage residential customers to claim entitlement to service under the General Service Tariff. To limit this incentive for rate switching, we recommend that the service under the General Service require a monthly minimum bill of three times the Fixed Monthly Charge of $9.34 for the residential tariff, or $28.02. This modification will not produce any increased revenue because the General Service Customers all use more than this amount.

In Chapter 3, we recommended the establishment of a demand-commodity transportation tariff for Transgas with the thought that competitive forces would encourage third-party suppliers to contract directly with customers with potentially significant cost savings to the end-user. It is important to point out that the tariffs for Haygas include the recovery of local distribution costs from all customers whether they are served directly from the Transgas system or from the local distribution system. The bypass of the Haygas system by third-party suppliers will limit the full recovery of the local distribution costs from customers in the large-volume customer class, thereby imposing an additional burden on small-volume customers. As a general rule, and with operations at or near capacity, that still is a desirable target. However, until the system approaches one hundred percent capacity, tariffs should be designed to create an incentive for customers to avoid bypass and third-party suppliers. For this reason a Haygas demand-commodity tariff is recommended for the customers in the large-volume class.

The Demand-Commodity tariff for large-volume consumers also limits the incentive for the customers in this class to switch to direct purchases from the Transgas Enterprise. Our proposed Demand

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Charge for this tariff is the same as the Transgas tariff for the same service The large-volume consumer Commodity Charge includes the costs for Haygas distribution costs on their system plus the Commodity Charge Haygas pays to Transgas for the gas that they purchase for resale to the large-volume class This rate form provides the same benefits for keeping the monthly bill variations low as was discussed for the Demand-Commodity tariff by Transgas The institution of the Demand-Commodity tariff will also create incentives for individual customers to manage their demand to reduce their average purchase cost below the Haygas average cost of $97 29 per MCM All these recommendations have the basic incentive to reduce the average costs for Haygas and in turn the average prices for all customers The change from a flat commodity rate to a demand-commodity tariff also allows the addition of new customers at a lower cost by using the released capacity from the customers who manage their demand for service on the existing system

Our suggested tariffs do not include the acquisition and installation of new gas meters for households Haygas estimates that the new gas meters, fully installed will cost approximately $100 per meter for a total outlay of some $44 5 million for the 445 000 meters that are to be eventually installed Charged out to the end-user over a period of 2 years, this would involve an additional temporary meter charge of $4 17 to $4 85 per month, for a range of interest charges between zero and 15% In accordance with Western practice these meters should be owned and maintained by Haygas as should all lines and equipment leading up to the meters Everything from the meters to the end-user's point of consumption should be the responsibility of the end-user In particular, Haygas needs to free itself from the responsibility it had under the old Soviet-style regime of installing or maintaining gas-burning consumer appliances This should become the function of a workforce of independent licensed and fully insured gas technicians that is yet to be developed

As to gas storage costs, these are included in the tariffs listed above We suggest that storage costs eventually should be accounted for separately and that the storage activity be charged as an unbundled activity to those customers who use the service However, the changes suggested here are so broad and wide-sweeping that it might be better to let the system settle down to its new modus operandi without the early introduction of other complicating matters Suffice it here to point out that the asset base used in the Transgas tariff calculations includes the asset value of the Abovian storage facilities, as does the correlation with US companies

Another issue best left for future consideration is the use of penalties to be added to the base tariff for going over or falling short of nominated transmission and distribution volumes This is standard practice in many Western Countries and certainly in the United States where accurate planning regarding the use of transmission and distribution capacities is imperative if operational efficiencies are to be achieved

The use of penalty provisions becomes important as the Armenian transmission system utilization approaches one-hundred percent peak delivery periods At that point, the establishment of overrun penalties and nominated contract deliveries will maximize the utilization of the existing pipeline system The level of these penalty charges will be effectively a multiple of the large-volume monthly demand charge When the system utilization approaches capacity someone must provide peak shaving capacity to meet the overrun deliveries The best measure of the tariff for overrun deliveries is the marginal peaking cost for shaving demand That peaking cost can be related to the marginal cost required to expanding underground storage capacity, or the marginal cost of customer use of alternative fuel replacement with liquefied hydrocarbon fuel, etc In the interim period the system can best approximate the marginal cost by pricing overrun volumes at the unit demand cost of $236 per month per MCM monthly maximum overrun delivery plus the cost of an equivalent quantity of light oil with the same energy content as the overrun volumes

Finally our recommended tariffs do not include rehabilitation expenditures We have scaled down, with significant concessions to the Armenian economic environment US operating costs for pipeline and distribution companies currently operating a well maintained system Additional expenditures

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associated with rehabilitation work will have to be added to the rate base where they will tend to increase tariffs However, the upward pressure on tariffs due to rehabilitation expenditures will be mitigated by offsetting downward pressure resulting from increases in natural gas throughput volumes

TRANSITIONAL RATE POLICIES

As mentioned at consumption rates of 100 million SCM per year, the residential tariffs are too high to be taken under serious consideration in Armenia However at the higher consumption rate of 1000 million SCM, which is definitely achievable for the simple reason that it had been achieved - and exceeded - in the past, the rates come down to a more realistic level We suggest that a temporary transition policy may be required to reach the 1000 million SCM residential consumption threshold

Let there be no mistake about it, the system will eventually have to stand on its own or it is not worth having Any transitional mechanism used to bring the system fully on line needs to have well defined limits with regard to both the time and the amounts allowed under such a system

There are in principle two ways to ease the transitional burden on the residential gas sector Either the State as one of the principal claimants on gas industry funds reduces its claim or the gas companies do The end-user and in particular in our case, the residential consumer is of course exempt from any concession since he is the intended beneficiary of it We would strongly argue that the gas companies not be asked to help close the gap These companies need all the revenues they can get to maintain and, hopefully, improve their current operating systems Under-financing has been their problem all along and a policy, transitional or not that keeps on providing insufficient revenues to the companies is self-defeating

We have mentioned earlier that tax concessions would be one way to ease the burden The section that follows will take a closer look at such a tax concession case

Tax Concessions

We have mentioned earlier the extraordinary increase in tax revenues that accrues to the State by virtue of the Western tariff methodology we are suggesting here As shown in Schedule ERC, the total tax revenue generated by the natural gas sector under the system now in place, and with current residential consumption rates of 100 million SCM per year, is on the order of $22 3 million per year (Line 78) Under the suggested system, still using a residential consumption rate of 100 million SCM per year, the tax revenue accruing to the State will be on the order of $47 9 million (Line 82, in Schedule F-2), yielding an increase in tax revenues of $25 6 million

This increase in tax revenues is understated for two reasons First since current practice involves deliveries to the District Heating Plants at the pre-VAT border price neither the State nor the operating companies receive any compensation for gas delivered to these plants which are currently using about 20% of the overall gas volume consumed in Armenia That means that the current State revenue of $22 3 million is in reality lower than indicated by about $4 1 million (20% of border VAT of $18 4 million plus combined company VAT's of $2 3 million Line 71, Schedule ERC) Since we do not suggest any permanent tax subsidy of any kind, this concession is not included in our Western case Schedule F-2 As a result the actual tax increase is not from $22 3 million, but rather from $18 1 million, for an additional increase in tax revenues of $4 1 million after adjustment for heating plant tax losses

Second, the increase in tax revenues is premised on 44 500 residential consumers using 100 million SCM throughout the year In reality, the number of residential customers will grow to around 150 000 by the end of the first year and residential consumption will be up at about 400 million SCM This will

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raise the growth-related tax revenue (mostly VAT) by an additional $6 1 million by the end of the year for an average year-around growth-induced adjustment of $3 1 million

Between the adjustment for tax losses associated with deliveries to district heating plants ($4 1 million) and additional tax revenues due to consumption growth ($3 1 million) average tax collections over the first year will be up by $7 1 million, for an overall growth in tax revenues of $32 8 million in the first year (from unadjusted increase of $25 6 million plus the district heating plant adjustment of $4 1 million and the growth adjustment of $3 1 million) This increase in tax revenue will grow more in future years along with projected consumption growth

As shown in the following table, it would take about $14 9 million (less than half of the increase in tax revenues) to fund the first year's residential tax concessions if the number of residential consumers remained static throughout the year Given the fact that the tariffs would be frozen for one year and the numbers of consumers would rise by perhaps as much as 100 000, the subsidies for the first year would rise to $32 6 million almost exactly offsetting that year's increase in tax revenues As mentioned, tax revenues would continue to rise in later years, and the tax concession would be cut by one third for very substantial tax revenue gains after the first year

FIRST-YEAR RESIDENTIAL TAX CONCESSION
MILLIONS OF DOLLARS PER YEAR

BEGINNING OF FIRST YEAR

Tariff 100*10^6 SCM	Average Residential Tariff	Residential Consumption MCM/Mo	Monthly Bill Dollars	Nbr of Service Connections	Haygas Revenue 10^6 Dollars
No Subsidy	$302 10	$0 187	$56 49	44 500	$30 17
Subsidized	$151 64	$0 187	$28 54	44 500	$15 24
Subsidy			**$27 95**		**$14 92**

END OF FIRST YEAR

Tariff 100*10^6 SCM	Average Residential Tariff	Residential Consumption MCM/Mo	Monthly Bill Dollars	Nbr of Service Connections	Haygas Revenue 10^6 Dollars
No Subsidy	$302 10	$0 187	$56 49	150,000	$51 38
Subsidized	$151 64	$0 187	$28 54	150,000	$101 69
Subsidy			**$27 95**		**$50 31**
			Average First-Year Subsidy		**$32 62**

The advantage of this approach is that the State incurs no losses through this tax concession policy, while the operating companies are not stifled by revenue reductions Problems arise if the increase in residential consumption falls short of expectations To make sure that the residential consumers assume their fair share of the cost recovery burden at the end of three years the three-year tax concession must be tied to a time table and not to actual residential consumption gains that may or may not materialize

In billing the residential customers under this tariff approach, the full cost-recovery amount should be shown listing the non-subsidy fixed monthly and variable fees, the latter assessed on the basis of actual consumption, minus a stated amount ($27 95 on average) labeled "State Contribution" or some such language At the end of the year, the State contribution will come down, but so will the newly assessed tariffs, since consumption volumes will have gone up in the meantime Substantial savings in subsidies could be achieved if throughout the subsidy period rate adjustments were to be made more frequently such as on a quarterly or at least semi-annual basis

As mentioned, another way to bridge the financial gap until residential consumption is restored to 1000 million SCM would be to have the operating companies reduce their revenue requirements for depreciation, profits and taxes on current asset values by reducing current asset values This could be done by mothballing those parts of the operating systems of Transgas and Haygas that are not currently utilized How this could be achieved and what the effects would be in the Armenian economy are the topics of the section that follows

Mothballing

The Transgas pipeline company currently runs at somewhere around 20% of original design capacity, and the Haygas residential supply system at less than half of that Mothballing is one legitimate if rarely used, way to deal with the issue of reducing the burden of unused capacity This involves taking the value of the unused facilities out of the rate base, but leaving that value on the balance sheet as "Assets Held For Future Use" As consumption rates rise and the utilization rates of Transgas and Haygas go up, the assets so set aside are then brought back into the rate base

There are two direct effects on company revenues that result from such a transitional policy Company profits are reduced in proportion to the reduction in the rate base and so are depreciation charges These reductions in company revenues carry over into reduced state revenues in three areas The profit tax comes down because profits are down, property taxes are reduced to the extent that they are based on asset values (a minor factor), and the VAT is reduced because incremental revenues at the pipeline and distribution stage are reduced

We have chosen to select a combination of Transgas and Haygas asset shifts that would be rational and defensible and that would produce approximately the same average end-user rate of $118 per MCM as the regular 1000 million SCM case Mothballing 20 0 percent of the Transgas assets and 25 0 percent of the Haygas assets would produce the desired result Under such a scenario total revenues decline by about $15 6 million at the beginning of the first year, as shown below

MOTHBALLING PRODUCTIVE FACILITIES
20% of Transgas and 25% of Haygas Facilities
Millions of Dollars per Year

Reduction in State Revenues		Reduction in Company Revenues	
VAT	$2 6		
Profit Tax	$2 7	Return on Assets	$8 2
Property Tax	$0 3	Depreciation	$1 8
Total State	$5 6	Total Company	$10 0

As the preceding Table shows under the stipulated mothballing scenario the State carries about one third of the transitional subsidy load, or $5 6 million, while the companies absorb the rest through reduced profits and depreciation allowances, at least for the beginning of the first year Put differently, the mothballing scenario gets roughly half its funding from reductions in returns on assets ($8 1 million), for an implicit overall return on assets of 11 6 percent (from (35 7-8 1)/238 1), compared to the nominal 15 0 percent target At the moment, of course the State is the shareholder of the corporation, but that is in the process of being changed The new co-owner would have to be willing to accept a temporary reduction of that magnitude in his rate of return for this option to be workable

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Our earlier remarks made in connection with rising numbers of consumers in a fixed one-year tariff environment hold true here as well Subsidy claims will rise significantly as the year goes by but they will not be fully offset by concurrent increases in growth-induced tax revenues Just how large the gap will be is difficult to say without a full-fledged model run designed to analyze this scenario which would take us beyond the scope of this project Be this as it may a 20 to 25% mothballing scenario is not sufficient to carry the subsidy for a full year Going beyond these percentages raises difficulties as regards the capitalization of impending rehabilitation investments as discussed in the following

The fact is that the pipeline at least and by implication the entire system is already in an implicit mothball situation As shown in Appendix A, the pipeline is currently worth about $339 million minus the estimated rehabilitation requirement of $193 million for a net depreciated value of $146 million (Hagler estimate) or $153 million (Armgasproject Institute estimate) This implies that about 57% of the current pipeline value is already carried as assets held for future use Going much below that percentage would not be advisable

We have suggested earlier, and we repeat this suggestion here, that the gas companies not be asked to carry any of the subsidy burden These companies need all the revenues they can get to maintain and improve their current operating systems As mentioned under-financing has been their problem all along, and a policy, transitional or not that keeps on providing insufficient revenues to the companies is self-defeating

GENERAL ISSUES

It is at times surprising how different economic systems can live side by side for decades with plenty of interaction through trade and travel, and yet be so unaware of each other's driving force and modus operandi In the course of this study we have had many opportunities to witness instances where concepts that were perfectly obvious to us such as profits or depreciation were difficult to get across in their full meaning to our counterparts, and vice versa Simple operational issues long resolved and forgotten in the West, become controversial and intensely debated problems here In the section that follows, we will take up some of these issues to clarify and emphasize points that have been made in the report and to raise a few new ones

Rates of Return

We have stipulated, without further discussion, that the return to the investor should be 15 0 percent of his investment No one has seriously challenged this proposition to date, but they will as the debate regarding our tariffs and tariff methodology evolves The time has come to defuse this debate and to provide the analytical background that led us to this suggested rate of return of 15 0 percent Much of what is offered here is based on similar work we have done in other NIS Countries While the numbers we will offer may be subject to debate, the principles behind them are universally accepted in the West, especially in Bilateral and Multilateral Lending Institutions

The Armenian tariff methodology currently in force does not directly encompass the concept of providing income to the investor who, until now has been the State The closest concept is a factor termed "profit" However, this profit does not have the same conceptual meaning as it does in the West In the Armenian application, profit is a mark-up on operating expenses from which long-term interest expenses are drawn Even here there is no determinative principle that provides an objective assessment of profits or of the costs behind them The allowance of profits and the allocation of funds is a matter of negotiation between the operating gas companies and the Energy Regulatory Commission and formerly the Ministry of Energy

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We recommend an internal rate of return of 15 0 percent on the value of used and useful assets This rate of return which has been used by the World Bank on similar (non-exploratory) oil and gas projects in Russia is of sufficient interest we hope to attract investors which the current Armenian methodology certainly fails to do Following international convention the used and useful assets are valued at replacement costs after depreciation based on a 30-year straight-line depreciation (SLD) regime which historically, has been in use in Armenia and in other countries of the former Soviet Union Since this procedure assumes that the system so valued is in good operating condition the asset value so determined must be reduced by the amount of capital that will be needed for rehabilitation

The rate of return for investors in international gas pipeline and distribution companies should consider the following elements

- Basic real (non-inflationary) rate of return on capital employed,
- Inflation adjustment,
- Additional return required to compensate for industry risk,
- Additional return required to compensate for structural risks regarding the corporate and financial structure of the company within the industry and
- Additional return required to reflect country risk (political, economic legal, regulatory, etc)

To estimate the **basic real rate of return on capital**, the yield on capital employed with minimum risk has been used (30-year U S Treasury Bonds) During the last four decades the yield on these types of bonds has averaged about seven percent, except during relatively short periods of high inflation However that is what is called the nominal yield since it contains inflation compensation At say 4% inflation a $1000-bond yielding a nominal 7% will provide a "profit" at the end of the year of $70 00 If at the end of that year the bond holder wanted to sell his bond he would get his nominal $1000 investment back which, if exchanged for other goods and services would be worth only about $960 In short, his investment has been eroded by inflation at the rate of 4% If the bond holder wanted to compensate for that erosion he would have to allocate $40 from his $70 profit to make his investment whole again in real terms Thus his real profit after **inflation adjustment** of 4% would have been $70 - $40 or $30, for a real rate of return of 3 0 percent To be sure this is a grossly simplified description of the process involved, but it does capture the essence of the inflation problem

Since Armenia has permitted its natural gas tariff to be calculated and denominated in US dollars, its own inflation risk does not enter the equation as a risk for the gas operating companies or for potential investors in these companies That is a risk for the end-user, but it does not enter the risk analysis a potential investor would undertake The investor would look at the risk of an escalating US dollar inflation, and the 4% rate we used would be reasonable and defensible

By comparison, we have listed an anonymous "Developing Country" where the tariff is denominated in that country's currency which is subject to a 10-percent annual inflation rate Here the required rate of return is substantially higher for that and for other reasons as shown in the Table that follows at the end of this section If the underlying investment instrument uses the local currency as the operating currency and the US dollar as the compensation currency, the exchange rate enters the picture as well That exchange rate will reflect the differential inflation rates However that discussion will take us too far afield Suffice it here to say that very high inflation risks and concomitant exchange rate risks have the capacity of killing otherwise worthwhile investment projects A reckless monetary policy, not present in Armenia, can thus create a situation where foreign investments will dry up

As regards **industry risks**, gas pipeline and distribution company investments are usually not as risky as investments in oil and gas exploration and development but they are certainly more risky than the US Treasury bond we have opted to use as our standard As a general rule gas transmission and distribution operations are relatively stable and recession-proof activities Hence we have opted to

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assign a two–percent risk premium here. In contrast, the industry premium for certain resource exploration and development investments may be higher than ten percent. Rank wildcats in relatively unexplored areas of low prospectivity can have exploratory risks of several hundred percent.

Structural risks depend upon the characteristics of the industry and the specific corporate and financial structure of the company. The structural risk is generally considered to be a separate and quantifiable risk that requires its own risk premium. The Armgasprom State Concern is a newly formed Government-owned joint stock company that is to be restructured and hopefully commercialized in the near future. However, at this time the development of the final corporate and financial structure has not been determined. Obviously there is risk and uncertainty in any new Government start-up company which may undergo significant change in preparation for commercialization. In addition, if many of the customers are unable or unwilling to pay for services in a timely manner or pay by barter, the risk premium to investors could be very high. To give an example from another Armenian industry, it is widely known that a significant percentage of customers of the power sector is either unable or unwilling to pay for services received with the result that the structural risk factor in that industry may be as high as six to eight percent. With regard to the gas industry, the advent and installation of gas meters for every end-user and the legislative authorization and technical capability to turn off gas deliveries to recalcitrant customers has reduced but not totally eliminated the structural risk. Still, based on uncertainties due to structural changes of the company and problems encountered in the collection of payments, it is not unreasonable to assign a structural risk factor of three percent.

A **country risk** of three percent has been assigned to Armenia, given the relative uncertainty in the development of the Armenian economy and concerns over issues needing resolution including the future independence and performance of the ERC. In contrast, the country risk premium is zero percent for the United Kingdom, the United States and Canada and up to five percent or more for some developing and politically sensitive countries.

We have therefore concluded that a recommended rate of return of 15 percent for the Armenian natural gas industry is appropriate. In contrast, regulated rates of return for pipeline and distribution companies in low risk countries (such as the U.S.) are generally eleven percent, and investments for similar companies in very high risk countries, are considered to require well over 20 percent. At higher risks going beyond the indicated range, investments generally will not take place. These rates are summarized in the following Table.

Rates Of Return for Pipeline and Distribution Company Investments

	High Risk Armenia	Low Risk (U.S.)	Very High Risk (Developing Country)
Basic Return on Capital	3.0	3.0	3.0
Inflation Risk	4.0	4.0	10.0
Industry Risk	2.0	2.0	2.0
Structural Risk	3.0	2.0	6.0
Country Risk	3.0	0.0	5.0
Total Return	**15.0%**	**11.0%**	**26.0%**

The 15% rate of return we suggest here is premised on the idea that this is a minimum rate designed to attract foreign investors. It so happens that joint-venture negotiations are under way, in fact well advanced, with the Russian gas giant Gasprom. That company has at least a dual objective as regards the establishment of a joint-venture company with the Armenian gas industry: it will look to a reasonable rate of return and it will want to secure a long-term outlet for its enormous gas reserves.

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Given this situation Gasprom may be willing to make long-term and short-term concessions on its rate of return that American or European investors would be unwilling to consider As regards long-term concessions the fact that Gasprom will probably own a majority interest in the joint-venture company will enable it to impose its own structure which surely they would be familiar with As a result the structural risk they (as opposed to other foreign investors) would assign would be no different from the structural risk that the market assigns to American gas pipeline and distribution companies In addition the Russians are intimately familiar with Armenian economic and political events To them the country risk arguably could seem to be more akin to the US country risk as perceived by US or European investors, so that Gasprom analysts might agree to assign a country risk factor of zero or near zero If so, the overall risk for Russians to invest in an industry that is basically stable if temporarily in disarray, and that they are intimately familiar with since they have built and run it for a long time, may be not very different from the overall US risk to, say, British investors for an acceptable long-term rate of return equal to or near the US rate of 11 0 percent

As regards short-term concessions, again in the interest of securing a long-term foothold in a growing market, Gasprom may be willing to reduce the risk factor, and the concomitant rate of return, by a few percentage points that would be phased out on a pre-arranged time schedule such as for example over five years In turn, Gasprom might ask for offsetting concessions from the Armenian Government such as a specified tax concession to be phased out over a similar five-year schedule The negotiating options available to the prospective partners are unlimited

Depreciation

Depreciation is a means for the investor to recover his investment As such depreciation serves to preserve capital funds if reinvested For the nation as a whole depreciation is meant to perpetuate its capital infrastructure Depreciation has nothing to do with return on assets

Example If a $300 million pipeline is subject to depreciation on a straight-line basis over the 30 years of the life of the pipe, the investor will receive 1/30th of his investment or $10 million every year for 30 years At the end of the life cycle of the line, he will have recovered his investment That $10 million a year is treated as a cost and included in the costs to be recovered on a cost-recovery tariff

A company will generally look upon depreciation as a source of funds and it will use these funds to promote its long-term objectives That may be capital expansion and an increase in future returns to the investor or it may involve partial or complete returns to the investor, via dividends on shares

If the investor only gets his investment back over the life cycle of his capital asset, he will not have made a profit on his investment In such a scenario, the investor is not likely to make the investment

Getting the investment back, without any profits is equivalent on a personal level to making a car available to an unrelated third party for say, 5 years If, at the end of five years, a new car of equivalent size and quality is provided and nothing else, the asset will have been made available for that time without any compensation No one in his right mind would agree to this In short depreciation without profit makes no sense It drives out capital

Similarly, an allowance for competitive profits in a cost-recovery tariff without a concurrent allowance for depreciation also drives out capital If a car owner gets a competitive rate of return on his car, say 12% but no allowance for depreciation, he will get something like $2 400 a year on a $20 000 car However at the end of the life of the car there is no provision for the investor to have an equivalent car The capital investment will simply have been consumed

Thus providing an allowance for a competitive rate of return without a depreciation allowance will consume the investment The pipeline investor will have received money payments in sufficient quantities to get his competitive rate of return but at the end of the life cycle of the pipeline he will not have recovered his investment and there are no funds to build a similar line For the country at large its capital base will have been partially depleted This is the problem Armenia is currently facing the depletion of its capital base and more specifically of its natural gas infrastructure, unless a regime is introduced that will allow for both, adequate returns and full depreciation

Under the old Soviet system, just like under the current US and Canadian systems a pipeline was subject to depreciation on a 30-year straight-line basis Since depreciation is charged out to the end user via tariffs this straight-line depreciation regime makes for a uniform and low-cost tariff component over the life of the asset If, on the other hand accelerated depreciation were permitted on a capital-intensive industry subject to regulated tariffs, the tariff would have to absorb very large depreciation charges in the early life of the capital asset As a result early tariffs would be much larger than they need to be

So whose depreciation is it anyhow? The original claimant to depreciation is the original investor/owner In the United States or in Canada, if an investor sells his company, the new owner is free to pay any price he wants If the company is a regulated monopoly, he can only bring the depreciated asset base into the rate base If he paid more than the depreciated book value, the excess payment remains unrecoverable through cost-recovery tariffs

What about Armenia and other Newly Independent States? Here the identity of the original investor/owner is not clear More than likely, it is the Russian State which built the system (or most of it anyhow) through one of its Ministries However, on the day of Armenian independence, the pipeline system accrued to the Republic of Armenia by virtue of its location The Republic of Armenia, therefore, became the new owner on the day of independence While there was no sale and no transfer of compensatory funds, there is a depreciated book value that attaches to the Armenian pipeline system and, through it, a claim on a source of funds resulting from depreciation

Depreciation can be abused In one known case involving a concession agreement the new operator had invested $30 million for a fifteen-year right to operate a gas pipeline system, with a five-year renewable option The pipeline system itself was estimated to have a book value of $340 million When the operator submitted its first rate application he had switched from the existing 30-year straight-line depreciation regime to 25% declining balance depreciation, doubling the depreciation charge in the process Clearly, since there were certain contractual obligations to rehabilitate the system, the operator had expected to use the accelerated depreciation route as a means of generating the cash flow required for this task. The impact on tariffs was deemed unacceptable

Operational Issues

Many operational issues have surfaced in our discussions with ERC and industry officials In those instances where we found discrepancies between Armenian and international methods of operation, we have pointed to international practice Suggestions along these lines are scattered throughout this report In this section we are collecting the most important operational suggestions to have them available in one convenient place

The need for **individual gas meters** is now recognized among all Armenian gas sector officials With the advent of the meters comes the capability to shut off service for non-payment The Armenian

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Energy Law now authorizes this ultimate and very effective enforcement device which is used with great success elsewhere in the world With the legislative and technical conditions met for shutting off service to non-paying customers and given the political will to implement such a policy the collection problem in Armenia will resolve itself in short order

The elimination of **payment by barter** is another problem that has been recognized as a major stumbling block to the introduction and administration of a cost-recovery tariff This is primarily a problem between the foreign supplier of natural gas and the importer We support Armenia's efforts to do away with barter transactions in the natural gas sector at the earliest convenience

We have mentioned before and we repeat here that **cross subsidies** of any kind through the use of tariff adjustments are not permissible In particular, the various daughter companies still attached to the Armgasprom State Concern must be made to make it on their own or they must be spun off The rate payer cannot be asked to financially support operations that are not directly related to the transmission and distribution of natural gas

We ourselves have suggested the use of subsidies (actually tax concessions) in the residential consumer market However, these tax concessions are transparent and outside the tariff calculations themselves They are to be administered by a separate agency of the Armenian Government such as the Ministry of Finance and Economics and, most importantly, they are limited in size and time They are strictly transitional concessions not to by used for more than three years

We believe that the **tax burden** on the natural gas industry, and probably on other industries, is too high The use of a 20 percent VAT in addition to a 25% profit tax does seem excessive by international standards We are afraid that the tax structure has a tendency to choke off industrial development in Armenia Of course, ours is not a tax analysis but we would suggest that the Armenian tax authorities take a hard look at the current tax regime The reason we have suggested tax concessions over mothballing as our preferred transitional subsidy mechanism is a reflection of our view that the taxing authorities can provide these funds with less pain to the Armenian economy than the natural gas industry

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APPENDICES

APPENDIX A

ASSET VALUATION

There will be little debate regarding the importance of developing and using accurate cost data in a tariff methodology that is rooted in the principle of cost recovery In North America where the cost-recovery methodology has been in existence for as long as there has been a pipeline industry the rules and regulations defining allowable costs and their use in calculating tariffs have been developed and refined over decades Some of the cost definitions have come about through the intervention of judicial proceedings where parties in disagreement had to resort to the courts to settle otherwise insolvable problems

It should come as no surprise that tariff related costs in formerly centrally controlled economies are extremely difficult to assess This goes for both the valuation of the original investment used in building the needed facilities and the assessment of annual operating and maintenance costs Typically, the original investment took place during the Soviet regime when prices of all goods including capital goods, were established by government fiat These prices did not reflect market values as they are understood in the West and, therefore the original cost of the facilities is essentially flawed, as is any subsequent depreciated value if based on historical investment costs

As regards operating and maintenance costs ("O&M costs"), they too are questionable for the central-control bias mentioned above Following Armenia's independence these costs may or may not be reflective of actual market conditions To the extent that depreciation charges are part of O&M Costs and given that their original capital base is much too low, this important component of O&M Costs is certainly too low In addition even if the non-financial components of O&M Costs reflect market prices they are biased downward because maintenance work on these lines has not been up to international standards Hence the use of otherwise accurate historical O&M costs incurred in Armenia would perpetuate inadequate operating budgets and would, therefore be unable to stop, let alone reverse, the ongoing process of deterioration of the pipelines and distribution system

In Armenia by far the most capital intensive natural gas operation is transmission through pipelines After re-assessing the value of the facilities serving the Armenian natural gas market the Armgasproject Institute which is attached to the Ministry of Energy placed the original investment value of the pipeline system at 72 3% of the overall natural gas industry with the distribution company running a distant second at 24 1% followed by gas storage facilities (3 0%) and almost imperceptibly low, by the Armgasprom Management Company at a fractional percent

We basically agree with the respective valuations of these subsystems but we had to re-affirm independently whether the actual values offered by the Armgasproject Institute are reasonable In doing so, we focused primarily on the pipeline system

To correct for the downward bias of formerly centrally controlled prices a cost structure was developed that provides estimates of pipeline investment costs for similar pipeline systems built in the

West These cost estimates reflect data submitted by construction and pipeline companies to regulatory authorities in the United States and Canada They cover in the case of construction costs literally hundreds of cases Their use in estimating the original pipeline investment costs in Armenia provides a reasonable standard one that has been widely accepted by pipeline analysts including analysts at the World Bank Estimates so developed rest on a large and statistically accurate database from a competitive and market-oriented economic environment

Pipeline Construction Costs

Pipeline construction costs vary considerably, depending on terrain, proximity to populated areas, river and mountain crossings, and a host of other factors As mentioned, the cost estimates for the construction of pipelines in the United States and in Canada we considered here literally rest on hundreds of individual pipeline construction projects The source of this information is the Oil and Gas Journal for 1995/6 cost data, Figure A-1, as well as for cost data covering all pipeline construction projects in the United States and most in Canada going back in time over a period of ten years These costs reflect line construction only They do not include compressor stations which based on estimates by various pipeline construction companies, add roughly another 15 percent to the line costs All of these data came originally from the US Regulatory Agency responsible for interstate pipelines, the Federal Energy Regulatory Commission (FERC)

The raw cost data and a straight-line correlation are shown in Figure A-1 As that Figure shows, average construction costs are subject to substantial deviations in part because extraordinary expenses such as incur in river crossings or extraordinary savings in unpopulated flat regions tend to substantially increase or reduce average costs To remove some of the data distortions that might be introduced by outliers of the ten-year data series the two highest and the two lowest data points were removed from the original data base for each line diameter Listed below the graph in Figure A-1 are construction costs with and without compressor stations, based on a straight-line correlation That correlation gave the best results of several correlation attempts, at a still less than ideal coefficient of determination of 0 66

Pipeline projects are subject to substantial set-up charges reflecting the movement of heavy equipment to the construction site and its installation at the site These costs are essentially the same for any given line diameter, regardless of the length of the pipe to be built For short sections of pipe these costs become an inordinate burden in terms of construction costs per mile of pipe built To remove part of the short-distance bias inherent in the 1995/6 data, we only considered pipeline projects five miles or more in length (8 kilometers or more), but even with that adjustment, a substantial short-term bias remains

Since we are dealing in Armenia with a long trunk line system, it would have been preferable to exclude pipeline projects of less than fifty miles However, if that had been done, there would not have been a sufficient number of projects for each of the stipulated line diameters to come up with a statistically usable estimate Hence, the database used here still contains many projects some 10 to 20 kilometers in length, leaving a substantial short-distance bias in place After lengthy discussions with industry representatives and having plotted several options for visual interpretation, Figure A-2 the remaining short-distance bias was removed by downgrading the resulting average construction costs by 15% This is a case where statistical information by itself does not provide satisfactory results calling for the introduction of expert judgment from selected sources

The final pipeline construction costs so developed are shown as a heavy line in Figure A-2 They correspond to the bolded Column above the graph labeled "O&G Journ, 1995/96, Minus 15%" These costs are close to the high end of a range of cost estimates provided to us on an earlier occasion by the Government of Kazakhstan The more important construction cost series originally

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Figure A-1

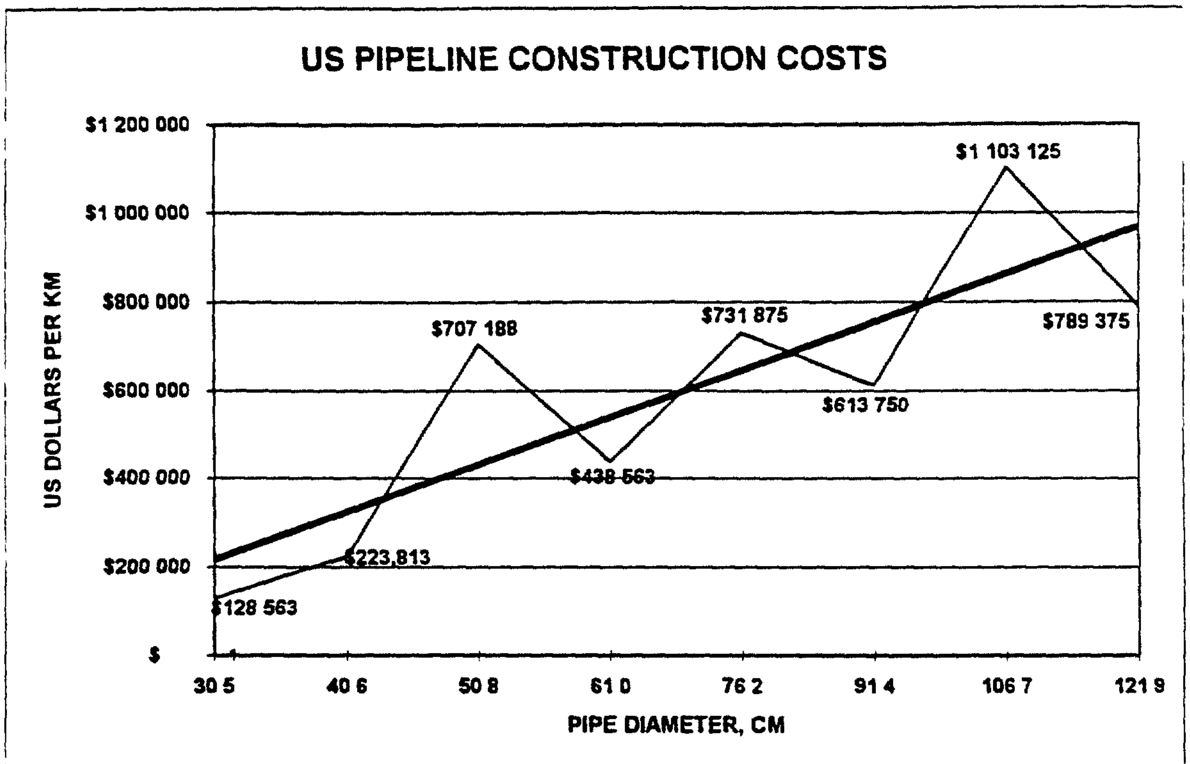
U S PIPELINE CONSTRUCTION COSTS

For Distances Greater than 5 Miles (8 km)

1995-1996

Diameter Inches	Diameter cm	Number of Projects	Average Length Miles	Average Length Kilometers	Cost US$/Mile	Cost US$/km
12	30 5	2	14 6	23 4	$ 205 700	$ 128 563
16	40 6	1	109 5	175 2	$ 358 100	$ 223 813
20	50 8	5	53 8	86 1	$ 1 131 500	$ 707 188
24	61.0	10	41 6	66 6	$ 701 700	$ 438 563
30	76 2	2	16 5	26 4	$ 1 171 000	$ 731 875
36	91 4	3	64 3	102.9	$ 982 000	$ 613 750
42	106 7	5	26 1	41 8	$ 1 765 000	$ 1 103 125
48	121 9	2	49 1	78 6	$ 1 263 000	$ 789 375

Source Oil and Gas Journal Nov 25 1996 pp 39-58



Pipe Diameter Inches	Pipe Diameter cm	Historical Costs US$/km	Least Square Costs No Compressors US$/km	Least Square Costs No Compressors US$/Mile	Least Square Costs Include Compressors US$/km	Least Square Costs Include Compressors US$/Mile
12	30 5	$ 128 562 5	258 530	$ 413 647	$ 297 309	$ 475 695
16	40 6	$ 223 812.5	339 379	$ 543 006	$ 390 286	$ 624 457
20	50 8	$ 707 187 5	420 228	$ 672 365	$ 483 262	$ 773 220
24	61 0	$ 438 562 5	501 077	$ 801 724	$ 576 239	$ 921 982
30	76 2	$ 731 875 0	622 351	$ 995 762	$ 715 704	$ 1 145 126
36	91 4	$ 613 750 0	743 625	$ 1 189 800	$ 855 169	$ 1 368 270
42	106 7	$ 1 103 125 0	864 899	$ 1 383 838	$ 994 634	$ 1 591 414
48	121 9	$ 789 375 0	986 173	$ 1 577 876	$ 1 134 098	$ 1 814 558
56	142 2		1 147 871	$ 1 836 594	$ 1 320 052	$ 2 112 083

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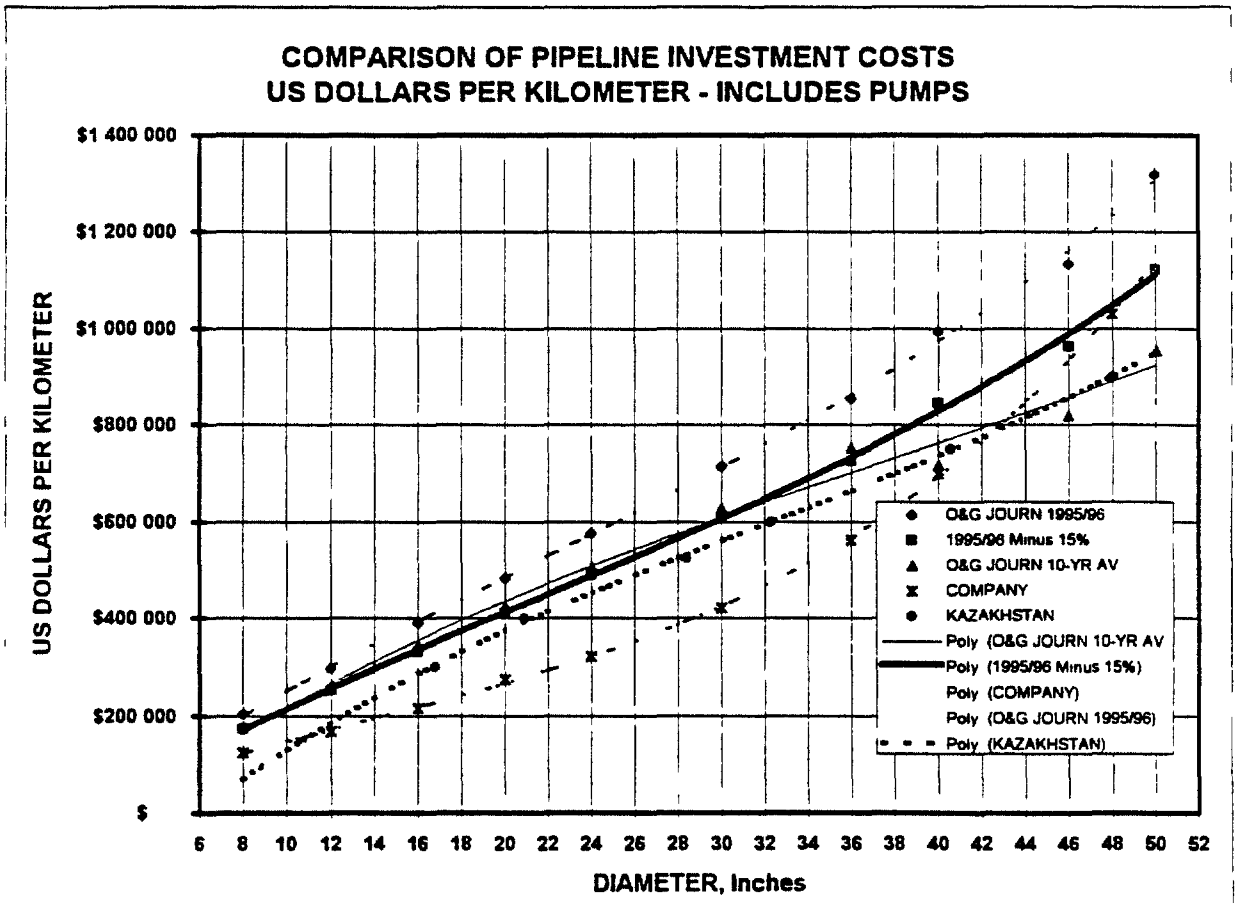
Figure A-2

COMPARISON OF PIPELINE INVESTMENT COSTS
US DOLLARS PER KM INCLUDES COMPRESSORS

DIAMETER	O&G JOURN 1995/96	O&G JOURN 1995/96 Minus 15%	O&G JOURN 10 YR AV	OIL COMPANY	KAZAKHSTAN
8	$ 204 332	$ 173 682	$ 177 395	$ 125 000	
12	$ 297 310	$ 252 713	$ 259 574	$ 168 750	
16	$ 390 287	$ 331 744	$ 341 753	$ 215 625	
16 8					$ 300 000
20	$ 483 265	$ 410,775	$ 423 932	$ 275 000	
20 9					$ 400 000
24	$ 576 242	$ 489,806	$ 506 111	$ 321 875	
28 4					$ 525 000
30	$ 715 703	$ 608,347	$ 629 379	$ 421 875	
32 3					$ 600 000
36	$ 855 163	$ 726 889	$ 752 648	$ 562 500	
40	$ 994 634	$ 845 439	$ 718 623	$ 700 000	
40 6					$ 750 000
46	$ 1 134 098	$ 963 984	$ 819 386		
48				$ 1 031 250	$ 900 000
50	$ 1 320 052	$ 1 122 044	$ 953 737		



RESULT ACCEPT OIL AND GAS JOURNAL 1995/96 MINUS 15% (TO COMPENSATE FOR SHORT-LINE BIAS)

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considered for use in the model are also shown in Figure A-2 They include the Oil and Gas Journal data mentioned before a theoretical model run by a major oil company and some Kazakhstan data As mentioned the final selection closely parallels the Kazakhstan high estimates

Given the dearth of cost data and their suspicious quality with investments for the most part dating from pre-independence central-control times the model sets out to build its own cost structure It does this by assuming that the line was built on the basis of an international competitive tender and that it is run under a transparent regulatory regime using a cost-recovery methodology

To deal effectively with the different line diameters that are disbursed throughout the Armenian pipeline system a series of standard lines, 1000 kilometers in length and of pre-selected diameters was chosen for the model calculations The diameters so selected were 8 16 24 30 36 and 42 inches Interpretation was used for other line diameters Using average US and Canadian cost data as discussed earlier, a first step in the modeling approach was to estimate current replacement costs of standard line segments Depending on the age and the length of the individual Armenian line segments their current values, net of depreciation were then calculated on the assumption that the lines operate at capacity and that they are in good working order

An alternative to the use of depreciated replacement costs would have been the original construction costs augmented by whatever capital maintenance or expansion projects might have taken place over the years and reduced by any capital retirements This would have been a difficult task, since the lines were originally built under central control performance, with funds paid out of Moscow, and at prices that typically, would have been distorted by price controls and artificial allocation systems Moreover, the pipelines were financed in a different currency rubles that have undergone spiraling inflation and uncertain exchange rates so that a tracing of costs in Armenian drams or in U S dollars would have been all but impossible

The different line segments of the Armenian natural gas pipeline system down to and including lines 325 mm in diameter (12 8 inches) are presented in Table A-1 entitled "Armenian Gas Pipeline System" The data used in that Table came from three different sources (Transgas the ERC and the Armgasproject Institute) These were reasonably accurate data sources with a variation of less than two percent between them The data we finally decided to use are the Armgasproject Institute data

Applying the estimated construction costs in Table A-1, Column 7 to the pipeline segments listed in Columns 1 through 4 and summing yielded the replacement value of $880 million of the pipeline system at large, Column 8 Net of depreciation, that current value was calculated to be $339 million Column 9 However, that value assumes that the system is in good operating condition Since it is not, one more adjustment must be made to the estimate of the current value of the system

As mentioned, the Armenian gas pipeline system is in need of substantial capital outlays to bring it into compliance with acceptable international operating standards TACIS has done a study of the capital investment that will be needed to achieve this They have prepared a priority listing of those line segments that are in urgent need of repair Their findings are summarized in Column 10 of Table A-1 All told the TACIS estimate of capital needs to effect the rehabilitation of the pipeline system is $193 million not counting contingencies These rehabilitation needs deducted from our current-value estimate or $339 million yields an adjusted current value of $146 million for all practical purposes confirming the Armgasproject Institute estimate of the pipeline system's current value of $153 million

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Table A-1

ARMENIAN GAS PIPELINE SYSTEM
Size and Estimated Current Value

Line	Section	Nominal Diameter mm	Nominal Diameter inches	Length Km	Year of Construction	Years in Operation	Original Value US $/KM	Original Value 10^6 US $	Depreciated Value 10^6 US $	TACIS Rehab Priority
	1	2	3	4	5	6	7	8	9	10
1	Circular Pipeline	1220	48.0	56.4	1989	9	1 000 000	$ 56 4	$ 39 5	Medium
2	Krasni Most-Berd	1020	40.2	61 8	1993	5	800 000	$ 49 4	$ 41 2	High
3	Ghazakh-Yerevan (KP 18-KP121)			103 0	1980	18		$ 82 4	$ 33 0	High
4	Ghazakh-Berd-Sevan			71 0	1986	12		$ 56 8	$ 34 1	Medium
				235.8						
5	Ghazakh-Yerevan	820	32.3	16.0	1971	27	620 000	$ 9 9	$ 1 0	Medium
6	Krasni Most-Alaverdi II	720	28.3	55 6	1985	13	550 000	$ 30 6	$ 17 3	High
7	Alaverdi-Vanadzor II			39 4	1985	13		$ 21 7	$ 12 3	High
8	Vanadzor-Gyumri II			54 1	1986	12		$ 29 8	$ 17 9	High
9	Ilyichevsk Yerevan			86 6	1985	13		$ 47 6	$ 27 0	Medium
10	Evlakh-Goris-Nakhichevan			79 3	1986	12		$ 43 6	$ 26 2	Medium
11	Ghazakh-Yerevan (Loop)			92 0	1970	28		$ 50 6	$ 3 4	Medium
12	Khazakh-Yerevan (KP121-KP174)			54 0	1984	14		$ 29 7	$ 15 8	Medium
13	Gyumri-Hoktemberian			60 0	1968	30		$ 33 0		Medium
14	Ghazakh-Yerevan			77 0	1961	37		$ 42 4		Low
				598.0						
15	Goris-Kafan-Kadjaran	530	20.9	55 4	1983	15	410 000	$ 22 7	$ 11 4	High
16	Angeghakot-Djermuk			45 0	1986	12		$ 18 5	$ 11 1	Medium
17	Yerevan-Hoktemberian			53 4	1967	31		$ 21 9		Medium
18	Branch Razdan-Abovian			50 0	1976	22		$ 20 5	$ 5 5	Medium
19	Sevan Vardenis Djermuk			114 0	1986	12		$ 46 7	$ 28 0	Medium
20	Krasni Most-Alaverdi I			55 1	1964	34		$ 22 6		Low
21	Alaverdi-Vanadzor I			44 3	1973	25		$ 18 2	$ 3 0	Low
22	Vanadzor-Gyumri I			58 1	1963	35		$ 23 8		Low
23	Gyumri-Maralik-Kamrashen			63 4	1968	30		$ 26 0		Low
24	Dilijan-Vanadzor			35 4	1961	37		$ 14 5		Low
				574 1						
25	Yerevan-Ararat	377	14.8	37.9	1961	37	300 000	$ 11 4		Low
26	Sevan Vardenis Djermuk	325	12.8	99 1	1969	29	260 000	$ 25 8	$ 0 9	Low
27	Name Unknown to Consultants			48 0	1977	21		$ 12 5	$ 3 7	
28	Djermuk Vaik			30 3	1986	12		$ 7 9	$ 4 7	Low
29	Vaik Yekhegnadzor			13 8	1987	11		$ 3 6	$ 2 3	Low
				191.2						
	GRAND TOTAL			1709.3				$ 880.3	$ 339 11	

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APPENDIX B

DERIVATION OF SCHEDULE F-2

Schedule F-2 reflects our best judgment of what natural gas tariffs would look like in Armenia based on our understanding of Armenian tax laws, but after adjustment to Western regulatory practices and costs, based on the concept of cost-recovery There are three distinct adjustments in Schedule F-2 The first dealing with the treatment of costs in the progression from the ERC Schedule through Schedule E-2 is relatively transparent and deserves little attention Cost changes in moving from Schedule ERC to E-2 will be mentioned without much elaboration The second and more obscure adjustment in costs is shown on Line 25 of Schedule F-2 entitled *Adjustment from US Costs* One should not lose sight of the fact that the changes introduced here, while somewhat complicated have a limited impact on tariffs The third distinct adjustment involves the transition from total operating expenses to revenue requirements This is the area where the tax and depreciation regime and other institutional forces come into play The mathematical treatment of this adjustment and the resulting overall and incremental tariffs shown primarily on the second page of Schedules ERC through F-2 (Lines 59 through 79 in Schedule F-2) will be dealt with in some detail in the third section of this Appendix

Cost Changes Schedule ERC through E-2

The ERC Schedule reflects our understanding of data provided to us by the Energy Regulatory Commission That schedule is the subject of a detailed discussion in Chapter 2 that needs no repetition here The move from Schedule ERC to ERC-2 simply involves the recognition that no Western tax or regulatory regime would recognize the treatment of long-term interests as profits These interest payments are moved from Line 60 in Schedule ERC, where they are shown as part of the overall profits rather than as a cost item, to Line 31 on Schedule ERC-2 Interestingly enough, the incremental tariff for Armgasprom is reduced by about $0 50 per MCM as a result of this shift, for the simple reason that interests as costs are now no longer subject to the profit tax of 25% With the profit tax reduced the revenue requirement declines and so does the VAT tax which is applied to the incremental revenue requirement It should be pointed out that the suggested treatment of long-term interests has been changed by law since we started our tariff work so that were we to start today with an Armenian tariff case to take in steps to an equivalent Western case, Schedule ERC-2 would be our starting point

The move from Schedule ERC-2 to A-2 simply involves the recognition of property taxes as a cost item Carried at zero in Schedule ERC-2, property taxes are introduced in Line 27 of Schedule A-2 The first step in this two-step introduction uses the old pre-1998 valuation of $8 0 million as the tax base, with a nearly imperceptible increase of three cents per MCM for the most capital-intensive of the

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three component companies Transgas That is also the overall increase in average tariffs to the end-user

Schedule B-2 is a repetition of Schedule A-2 in all respects except that the latest (1998) valuation of the system $238 million was used as the property tax base That change raises the average tariff to the end-user by about one dollar per MCM from $78 10 to $79 15

Schedule C-2 is significant for two reasons It introduces depreciation in accordance with Western practices and it is the first change to raise tariffs by a noticeable amount $5 75 per MCM There are no methodological difficulties in Schedule C-2, and there are none in the following Schedule E-2 That Schedule introduces the concept of a Western type rate of return, which is here introduced at the suggested level of 15 0% on the depreciated asset valuation, a proxy for the normal rate base which generally also includes working capital The introduction of the rate of return on rate base is the single most significant move in raising tariffs from the original ERC Schedule to the final F-2 level of $128 10 per MCM, to be discussed in the next section Methodologically, though this merely involves the replacement of one revenue requirement item with another one Hence there are no new issues or complications that warrant discussion in the current context

Cost Changes Schedule E-2 to F-2, Adjustment to US Cost Standards

The introduction of straight-forward cost adjustments, Schedules ERC through E-2, answers the question of what the tariff and the claims by various market participants would be, if a Western regulatory regime were imposed on the existing Armenian cost structure This process does not deal with the issue of the sufficiency of the allowed or expended costs themselves Has the natural gas system in Armenia slipped into neglect because of an inadequate tariff and regulatory regime or was the principal factor in this process a lack of funds that would have prevailed even in the presence of a Western system? Schedule F-2 reflects our attempt in adjusting the allowable costs in Armenia to what they might have been in a Western style system It is in this area where exact answers will never be developed The process in getting from Schedule E-2 to the addition of Line 25 in Schedule F-2, labeled *Adjustments for US Costs*, involves a good deal of judgment Because this step involves more subjective input that all the others described earlier, this may well be the area where most of the debate will focus That would be a regrettable development, since the move from Table E-2 to F-2 involves a relatively minor increase in tariffs

Transgas Pipeline

There are three cost adjustments in all, one for each component company Starting with the simplest adjustment, that for the Transgas Pipeline, we have developed Table B-1 which produces a final figure in Column 6, Line 23, (903,033 in thousands of drams) that is entered as the cost adjustment on Line 25 of Schedule F-2 This adjustment is based on a detailed review of the total transmission expenses of two US pipelines of approximately the same length and with similar characteristics as the Armenian Transgas Line The two companies so selected were Algonquin Gas Transmission Company and East Tennessee Natural Gas Company These two companies surfaced following a network search that involved around 100 US pipeline companies and that led to the selection of four companies that seemed to warrant close scrutiny, the other two being the Northern Border and Kern River Pipeline Companies We got in touch with each of these four companies and received from them their latest FERC Forms 2, Annual Reports, Security and Exchange Commission 10-K Statements and additional written and oral information on follow-up letters and phone calls The willingness of these companies to cooperate with us in producing information that is useful for the development of the gas sector in Armenia is greatly appreciated

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Following discussions with officials of the ERC Northern Border and Kern River were discarded although a trial run performed as a matter of interest revealed that their inclusion would have produced almost identical incremental pipeline tariffs We are pointing this out here for the simple reason that a four-pipeline statistical base is more solid than one based on two lines i e that the statistical validity of our two-pipeline discussion is in reality better than appears at first sight

We decided early on that the cost allocation factor to be used in the pipeline case would be total assets The source of our cost data was the FERC Form 2 which is prepared by US interstate pipelines for the US Federal Energy Regulatory Commission and submitted under oath These data are comprehensive and precise and they follow a format that line by line and page by page is the same for all companies

Column 1 in Table B-1 lists the line items that are being monitored and submitted to the FERC on an annual basis Listed on Line 24 of that Table are the original investment figures, in hundreds of millions of US Dollars, for the Algonquin and East Tennessee Pipelines The actual expenditure figures in the FERC Forms 2, divided by their respective original investment figures yielded the transmission expenses, in US dollars per one hundred million dollars of assets for the two Pipelines Columns 2 and 3 These numbers were averaged in Column 4 of Table B-1 for average transmission expenses of $4 377 million per one hundred million dollars of pipeline assets, Line 21 Multiplying the line items in Column 4 with the Transgas depreciated asset value of $165 million (Line 24) yields the Transgas Pro-Forma numbers in US Dollars (Column 5) and in thousands of drams (Column 6) The pro-forma expenses of 2 361 billion drams, Line 21, reflect Armenian cost data after adjustment for US cost standards This compares with Schedule E-2 expenses of 1 459 billion drams (Line 24) for an upwards adjustment of 903 033 million drams for the pipeline costs only This number was then entered as the correction factor on Line 25 of Schedule F-2 Two additional explanations are needed at this point

1 Not all line items in Column 5 were derived as described In particular the item labeled *Gas for Compressor Station Fuel* was the only item that is identical to a Transgas line item and it had been given the ERC-assigned low value of 74 million drams The value was accepted by us as stated, since the Pipeline Company does not use its own compressors to ship the gas While Transgas owns and operates compressors these are used intermittently in connection with the Company's gas storage operations at Abovian The power for transmitting gas is derived from compressor stations that are located outside Armenia and the cost of the gas used in developing that power is included in the border price

   The second individual cost item treated differently in Column 5 is the item in Line 9 *Transmission and Compression of Gas by Others* That is not an operational feature at present, so we assigned a value of zero for this item

2 Another more relevant item to be discussed is the use of the discounted value for the Armenian asset base, compared to the value of the initial investment (plus additions minus retirements) for the US Companies That frankly was a judgment call We know that operations in Armenia will not be as expensive as in the States so we arbitrarily assigned the discounted value of the Armenian asset base as the allocation factor Given the uncertain validity of that asset value, that seemed to be a reasonable and at least a consistent way to reduce equivalent Armenian cost data If initial investment data had been used the equivalent costs in Columns 5 and 6 would have been 2 8 times higher

Armgasprom

While the Management Company Armgasprom is responsible for the financial contract and management functions of the entire gas industry the Distribution Company Haygas has a vastly

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more complex administrative and general expense structure than the Pipeline Company primarily because the Distribution Company has a much larger number of customers As a result the Distribution Company is expected to control most of its own administrative functions including customer accounts, sales expenses and administrative and general expenses For the purpose of allocating US cost standards we have opted to shift all of the pipeline company's administrative and general expenses to Armgasprom while leaving the equivalent expenses of the distribution company within that company As far as the average cost of gas to the end-user is concerned this judgment call is of no consequence It just makes the Transgas incremental tariff a little lower and the Haygas incremental tariff a little higher, but as discussed earlier this adjustment is of relatively little overall significance Greater fine-tuning is, therefore, not warranted in our opinion until the use of Western cost accounting provides a solid basis for change from the proposed procedure

Table B-2 reflects, in Columns 2 and 3, the administrative and general expenses of the two representative US Pipeline Companies, relative to their respective asset bases Their average Column 4, multiplied by the depreciated asset base of Transgas yielded the Armgasprom Pro-Forma costs, in US dollars (Column 5) and in thousands of drams (Column 6) That latter number (1,975,239) is the cost-adjusted operating cost of Armgasprom Given that Company's earlier cost allocation of 751,000, the difference, 1,224,239 thousand drams is the suggested adjustment as posted on Line 25 of Schedule F-2

Haygas

As mentioned the Haygas Distribution Company has by far the most complex cost structure of the three Armenian gas companies The US regulatory Agency, FERC, recognizes the following major categories as significant cost centers in a distribution company

- Operations Expenses, consisting of Operations and Maintenance Expenses
- Customer Accounts Expenses
- Customer Service and Informational Expenses
- Sales Expenses and
- Administrative and General Expenses, again subdivided into A&G and Maintenance Expenses

We again searched for representative US distribution companies and elected three for detailed discussion Of these, two were chosen for consideration in our rate adjustment following discussions with representatives of the Armenian ERC These two companies are the Laclede Gas Company in St Louis Missouri, and the Minnegascompany in Minneapolis, Minnesota The criteria used in choosing these companies were principally size and climatic similarity Again, we appreciate the generosity that was exhibited by the management of these companies in going out of their way in providing us their in part confidential data

In making our adjustment of Haygas operating expenses to reflect US cost standards we made the judgment call that distribution and maintenance expenses should be allocated on the basis of the Haygas distribution plant asset base shown on Line 16 in Table B-3 Going through the now-familiar routine of averaging expenses per 100 million dollars of asset base and multiplying that average with the Haygas depreciated asset base of $72.2 million yielded the first of a series of equivalent US costs, this one for distribution and maintenance expenses amounting to 2,316,320 thousand drams, Column 6 Line 3 To soften the impact on Armenian costs, we again used depreciated asset values for the Armenian distribution plant, as discussed in connection with Transgas cost adjustments

It seemed more accurate to use the number of customers as the basis of cost adjustments for costs associated with customer accounts customer service informational service and sales expenses The relevant expenses per 10,000 customers are shown on Lines 4 through 8 Columns 2 and 3, using

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the active customer count as of February 1998 in Armenia of 30 660 To put this in perspective the number of customers in Armenia at one time was as high as 450 000 roughly half of which were located in Yerevan Again the averaging routine described earlier was used in arriving at the equivalent US cost estimates on Lines 4 through 8 in Column 6

Having dealt with operations and maintenance expenses and with customer account and related expenses as described above this left the distribution companies' administrative and general expenses to be adjusted We felt that these costs should be adjusted on the basis of the general size of operations as measured by overall costs minus the A&G costs that are the subject of this adjustment process By way of an example, the A&G costs of the Laclede Gas Company are listed below and their use is illustrated with actual numbers that are not directly visible in Table B-3

Total Distribution Costs (O&M Costs)	$42 696 399
Total Customer Accounts	$26 008,684
Customer Service Costs	$597 681
Total Sales Expenses	$3,397,531
Total A&G Costs	$26,817,840
Total distribution Costs	$99 518 135

The total distribution costs shown above minus the A&G costs to be adjusted yield the adjustment basis used on Lines 9 through 11 of Table B-3 For example in cell C31 of the spreadsheet underlying Table B-3, the denominator is shown to be total O&M expenses ($99,518 135 above) minus total A&G costs of $26,817,840 Using the adjustment mechanism described above and going through the familiar adjustment process yields the suggested A&G cost of 1,258,391 thousand drams, Line 11, Column 6

Adding the various cost estimates in Column 6 yields the final estimate of operations and maintenance costs for Haygas, for a total of 4,308,697 thousand drams roughly three times the ERC suggested number To reach that number, the addition of 2,899 979 thousand drams is required on Line 25 of Schedule F-2

Changes in Moving from Total Adjusted Operating Expenses to Revenue Requirements

The movement from total adjusted operating and maintenance expenses (Line 26, Schedule F-2) to total operating costs, Line 35, is straightforward It involves the addition of depreciation, various minor taxes and interest expenses to total operating and maintenance expenses The individual line items to be added have either been discussed or are self-explanatory Hence they require no discussion here

The total operating costs on Line 26 in Schedule F-2 have been re-entered on the second page of Schedule F-2 on Line 59 in thousands of drams and on Line 70 in millions of US dollars Both units are used because the ERC Resolution 7 defining maximum tariffs uses both units

Procedurally each component company is presumed to receive the gas perform its function in handling it add its incremental tariff to it and then sell it to the next company down the line In fact the incremental tariff is derived from the difference in the cost of purchasing the gas and the revenues generated when it is sold To the extent that technological losses are involved the incremental tariff so developed includes those losses which were given to us as 3 8% for Transgas and 1 68% for Haygas

Beginning with Armgasprom and using the assumed import volume of 1 672 BCM per year the Company owes the importer $91 988 million at the import price of $55 00 per MCM In addition it owes the State $18 398 million in Value Added Tax based on a 20% tax rate The total import costs faced by Armgasprom, then amount to $110 385 million Line 57

To this amount Armgasprom will add the cost of its services plus any additional charges it incurs in performing its service That includes the Company's profits taxes on those profits and any VAT charges applied to Armgasprom incremental costs These calculations are shown on Lines 59 through 68

Under the Western regulatory regime, company profits are established as a percentage of the depreciated asset base which for Armgasprom is 561 million drams, Line 61 That base times the suggested return on assets of 15 0% yields an after-tax profit of 84 15 million drams (Line 62) To actually collect that profit, Armgasprom must be permitted to add the expected profits tax to its invoice to the Pipeline That profit tax is calculated by dividing its profits by 1 0 minus the profits tax rate of 25% Even with that adjustment, the company must increase its charges further to compensate for the VAT of 20% which is charged against its total value added, i e , against its costs plus profits plus profit taxes which amounts to 3 185 billion drams, Line 65 20% of that amount equals 637 million drams (Line 67) which, when added to 3 185 billion yields the total additional revenue requirement of 3 823 billion drams (Line 66) This is the total amount to be added to Armgasprom's import bill The calculation is repeated in the US dollar section of Schedule F-2 Lines 70 through 76

Using the current exchange rate of (approximately) 500 drams per US dollar, the total revenue requirement of 3 823 billion drams translates into $7 645 million Line 72 Adding that amount to Armgasprom's import bill of $110 385 million (Line 57) yields the amount of its invoice to Transgas of $118 030 million That amount, divided by its annual sales volume to the Pipeline (1 6725 BCM) yields Armgasprom's overall tariff of $70 571 per MCM and the difference between the tariff it charges and the tariff it pays on receipt of the gas ($66 00 per MCM, including the VAT) is that company's incremental tariff, $4 571 on Line 79

This is the basic procedure that was followed for the other two companies, Transgas and Haygas The one difference, noted earlier, is that the pipeline and distribution operations involve technological losses which are automatically included in the incremental tariffs by virtue of relating the sales invoice to actual sales which are gas purchases minus technological losses

The rest of Schedule F-2, Lines 70 through 101 shows the method that was used to calculate total payments made to the principal claimants in the gas industry These are the importer, the State the Company, and the Shareholder which, for the time being, is the State in Armenia These calculations are straightforward They need no further explanation The results of the work done in this section of Schedules ERC through F-2 have been discussed in some detail in Chapter 2

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Table B-1

TRANSMISSION EXPENSE STANDARDS
TYPICAL AMERICAN GAS PIPELINE COMPANY
APPROXIMATE SIZE OF ARMENIAN GAS PIPELINE SYSTEM

Data From FERC Form 2

(1)	LINE	ALGONQUIN GAS TRANSMISSION COMPANY (2)	EAST TENNESSEE NATURAL GAS COMPANY (3)	ALGONQUIN EAST TENNESSEE AVERAGE (4)	TRANSGAS PROFORMA (5)	(6)	LINE
TRANSMISSION EXPENSES		TRANSMISSION EXPENSES US$ per $100 Million Assets			US Dollars	10^3 Drams	
Operation Supervision and Engineering	1	$388 957	$330 685	$359 821	$592 949	296 475	1
System Control and Load Dispatching	2	137 365	144 577	140 971	232 306	116 153	2
Communication System Expenses	3	87 860	154 636	121 248	199 805	99 902	3
Compressor Station Labor and Expenses	4	323 025	596 829	459 927	757 914	378 957	4
Gas for Compressor Station Fuel	5	173 085	2 063 105	1 118 095	148 000	74 000	5
Other Fuel and Power for Compressor Stations	6	22 830	21 697	22 263	36 687	18 344	6
Mains Expenses	7	358 920	1 417 849	888 384	1 463 968	731 984	7
Measuring and Regulating Station Expenses	8	136 631	344 146	240 389	396 136	198 068	8
Transmission and Compression of Gas by Others	9	166 339	744 647	455 493	0	0	9
Other Expenses	10	39 376	48 334	43 855	72 269	36 134	10
Rents	11	13 732	60 130	36 931	60 858	30 429	11
Total Transmission Operation	**12**	**$1 848 120**	**$5 981 316**	**$3 914 718**	**$3 960 893**	**1 980 446**	**12**
Maintenance Supervision and Engineering	13	$73 101		$36 550	$60 232	30 116	13
Maintenance of Structures and Improvements	14	32 280	28 978	30 629	50 473	25 237	14
Maintenance of Mains	15	137 362	250 007	193 684	319 172	159 586	15
Maintenance of Compressor Station Equipment	16	61 494	140 359	100 926	166 317	83 158	16
Maintenance of Measuring and Regulating Station Equipment	17	54 409	96 538	75 473	124 372	62 186	17
Maintenance of Communication Equipment	18	21 685	26 099	23 892	39 371	19 686	18
Maintenance of Other Equipment	19	0	3 024	1 512	2 491	1 246	19
Total Maintenance	**20**	**$380 330**	**$545 004**	**$462 667**	**$762 429**	**381 214**	**20**
TOTAL TRANSMISSION EXPENSES	**21**	**$2 228 450**	**$6 526 320**	**$4 377 385**	**$4 723 322**	**2 361 661**	**21**
Schedule E 2 Transmission Expenses	22					1 458 628	22
Increase After US Cost Adjustment	**23**					**903 033**	**23**
Total Transmission Assets Hundreds of Million US$	24	7 05	2 00		1 65		24

Table B-2

ADMINISTRATIVE AND GENERAL EXPENSE STANDARDS
TYPICAL AMERICAN GAS PIPELINE COMPANY
APPROXIMATE SIZE OF ARMENIAN GAS PIPELINE SYSTEM

Data From FERC Form 2

	LINE	ALGONQUIN GAS TRANSMISSION COMPANY	EAST TENNESSEE NATURAL GAS COMPANY	ALGONQUIN EAST TENNESSEE AVERAGE	ARMGASPROM PROFORMA		LINE
		Transmission Expenses US$ per $100 Million of Assets			US Dollars	10^3 Drams	
(1)		(2)	(3)	(4)	(5)	(6)	
Administrative and General Salaries	1	$941 212	$1 105 315	$1 023 263	$1 686 236	843 118	1
Office Supplies and Expenses	2	452 019	673 679	562 849	927 519	463 759	2
Property Insurance	3	24 536	1 213	12 874	21 216	10 608	3
Injuries and Damages	4	74 016	37 571	55 793	91 942	45 971	4
Employee Pensions and Benefits	5	312 907	684 256	498 582	821 612	410 806	5
Regulatory Commission Expenses	6	110 799	9 836	60 318	99 397	49 699	6
Rents	7	204 584	109 722	157 153	258 972	129 486	7
Total Operation	8	$2 120 073	$2 621 591	$2 370 832	$3 906 894	1 953 447	8
Maintenance of General Plant	9	$52 896	$0	$26 448	$43 584	21 792	9
Total Administrative and General Expenses	10	$2 172 969	$2 621 591	$2 397 280	$3 950 478	1 975 239	10
Schedule E 2 Administrative and General Expenses	11					751 000	11
Increase After US Cost Adjustment	12					1 224 239	12
Total Assets Hundreds of Millions of US Dollars	13	7 05	2 00		1 65		13

Table B-3

DISTRIBUTION EXPENSE STANDARDS
TYPICAL AMERICAN DISTRIBUTION COMPANY
APPROXIMATE SIZE OF ARMENIAN DISTRIBUTION SYSTEM

Data From FERC Form 2 and Minnesota Dept of Public Service Report

	LINE	LACLEDE GAS COMPANY	MINNEGASCO	LACLEDE MINNEGASCO AVERAGE	HAYGAS PROFORMA		LINE
(1)		(2)	(3)	(4)	(5)	(6)	
OPERATIONS AND MAINTENANCE EXPENSES							
		Expenses per $100 Million Distribution Plant			**US Dollars**	**10^3 Drams**	
Total Distribution Expenses							
Distribution Operation Expenses	1	$3 945 552	$5 017 449	$4 481 501	$3 236 943	1 618 472	1
Distribution Maintenance Expenses	2	2 481 452	1 383 192	1 932 322	1 395 697	697 848	2
Total Distribution Expenses	3	**6 427 004**	**6 400 642**	**6 413 823**	**4 632 640**	**2 316 320**	3
		Expenses per 10 000 Customers					
Customer Account and Related Expenses					**US Dollars**	**10^3 Drams**	
Customer Accounts Operation Expenses	4	$316 957	$288 949	$302 953	$928 853	464 426	4
Uncollectible Accounts	5	105 638		52 819	161 942	80 971	5
Total Customer Accounts Expenses	6	422 594	288 949	355 771	1 090 795	545 398	6
Customer Service and Informational Expenses	7	9 711	139 550	74 630	228 817	114 408	7
Sales Expenses	8	55 204	41 574	48 389	148 361	74 180	8
		Expenses per $ 1 Million Non-A&G Expenses			**US Dollars**	**10^3 Drams**	
A&G Operation Expenses	9	$361 004	$452 485	$406 744	$2 481 390	1 240 695	9
A&G Maintenance Expenses	10	7 879	3 724	5 801	35 392	17 696	10
Total Administrative and General Expenses	11	**368 882**	**456 209**	**412 546**	**2 516 781**	**1 258 391**	11
TOTAL O & M EXPENSES	12	**$99 518 135**	**$98 314 483**	**$98 916,309**	**$8 617 395**	**4 308 697**	12
Schedule E 2 Transmission Expenses	13					1 408 718	13
Increase After US Cost Adjustment	14					**2 899 979**	14
Total Regular Full Time Employees	15	2 069	1 306				15
Distribution Plant US $	16	664 328 164	592 668 349		72 229 000		16
General Plant US $	17	48 195 033	91 918 366				17
Total Gas Plant, US $	18	712 523 197	684 586 715				18
CUSTOMERS							
Residential Sales	19	577 106	576 783				19
Commercial & Industrial Sales	20	38 347	52 469				20
Total Customers	21	615 453	629 252		30 [illegible]60		21
THERMS OF GAS SOLD							
Residential Sales	22	642 367 244	750 471 000				22
Commercial & Industrial Sales	23	315 243 343	382 341 000				23
Total Therms Sold	24	957 610 587	1 132 812 000				24

APPENDIX C

CUSTOMER CLASS ALLOCATIONS

HAYGAS DISTRIBUTION COMPANY

In Chapter 3, we briefly discussed the allocation mechanism we used to create the Haygas Proforma Income Statement That discussion provides a fair idea of what was done but it does not give sufficient detail for an analyst to fully understand the process and to introduce changes for excursions he might wish to undertake on his own It is the purpose of Appendix C to furnish the missing detail

Allocation of Assets to Classes of Service

The principal allocation factor for incomes by class of customers Table 13 in Chapter 3 is the asset base of each class These asset bases are shown on line 31 of Table 13 under the title "Appraised Value" Up to this point there has been no discussion as to where these asset values came from

We did not obtain a detailed listing of Haygas assets in time for incorporation in this report In any event, if we had received such a listing in time, we would have had to modify it substantially to fill gaps and to take into consideration differences in US versus Armenian accounting procedures Given these circumstances, we used a representative US distribution company, the Minnesota Gas Company ("Minnegasco") to estimate the assets of the individual Haygas customer classes This was done in Table C-1 where the Minnegasco total plant value is listed on Line 14 of Column 1 ($684,586,715)

Based in part on confidential company information provided us through the courtesy of Minnegasco officials, we scaled the Gross Plant in Service of Haygas (Line 11 74 808 billion drams) in accordance with the line items listed on Lines 1 through 10 The Total Amounts so developed were then allocated as described in the notes listed in Table C-1 and explained below

Note 1 -- Assets related to the General Plant were allocated using the allocated Total Distribution Plant shown on Line 9 For example Table C-1 allocates the Total Amount of the general plant on Line 10 (10 044 billion drams) to the residential service customer class by applying the ratio of 38,168 to 64,763 to that amount The resulting allocated amount appears in Column 3, Line 10, as 5 92 billion drams

Note 2 -- Assets related to the use of capacity were allocated using the Peak Day Delivery Shown on Line 16 of Table C-1 For example, the table allocates the cost of the pumping and regulating equipment on Line 4 in the amount of 1 642 billion drams to the residential service customer class by applying the ratio of 822 MCM to 8 816 MCM to that amount The resulting allocated amount appears in Column 3, Line 4, as 153 million drams

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Note 3 -- Assets related to the density of customers served were allocated on the Number of Customers Shown on Line 15 of Table C-1 For example Table C-1allocates the cost of the meters on Line 6 in the amount of 4 738 billion drams to the residential service customer class by applying the ratio of 44 500 customers to 49 088 customers to that amount The resulting allocated amount appears in Column 3 Line 6 as 4 295 billion drams

Note 4 -- The Accumulated Depreciation was allocated on the basis of the allocated Gross Plant in Service shown on Line 11 For example Table C-1 allocates the accumulated depreciation in the amount of 38 693 billion drams to the residential customer class by applying the ratio of 44 088 to 74 807 to that amount The resulting allocated amount appears in Column 3, Line 12, as 22 804 billion drams

Note 5 -- Distribution Mains serve a dual purpose The assets are related to the density of customers served The assets are also related to the capacity of the mains to deliver the gas during the peak delivery period Accordingly, the asset allocation is a two-step process

The first step separates the total asset value between these two functions using a minimum cost system to establish the portion of the total assets related to the density of the customers Using Minnegasco property records, the minimum cost system related to the total cost of mains is in the ratio of 1 to 3 432 This ratio applied to the total cost of 30 813 billion drams on Line 3 Column 1 develops the cost of the minimum customer-related system as 8 978 billion drams The cost related to capacity then is the difference between the customer-related system and the total cost of mains or 21 834 billion drams (from 30 813 minus 8 978 billion drams)

The second step uses the two allocation factors for customer density (number of customers) and capacity (Peak Day Delivery)

As to customer density, Table C-1 allocates the minimum system amount of 8 978 billion drams to the residential service customer class by applying the ratio of 44,500 customers to 49,088 customers to that amount The resulting allocated amount is 8 139 billion drams

As to capacity, the Table allocates the capacity amount of 21 834 billion drams to the residential service customer class by applying the ratio of 822 MCM to 8,816 MCM to that amount The resulting allocated amount is 2 035 billion drams

The combined asset amount for the residential service customer group is the sum of 8 139 and 2 035 billion This total of 10 175 drams appears in Column 3, Line 3

Note 6 -- Service Lines also serve a dual purpose The assets are related to the length of the pipes used to connect the customer's facilities with the distribution main and to the diameter of the service line that is required to provide the peak-day delivery

The first step separates the total asset value between these two functions using a minimum cost system to establish the portion of the total assets related to the length of pipe needed for connecting each customer Using Minnegasco property records, the minimum cost system related to the total cost of service lines is in the ratio of 1 to 1 0833 This ratio applied to the total cost of 21 960 billion drams on Line 5 Column 1 develops the cost of the minimum system as 20 270 billion drams The cost related to capacity then is 1 689 billion drams

The second step uses the two allocation factors for customer density (number of customers) and capacity (Peak Day Delivery)

As to customer density Table C-1 allocates the minimum system amount of 20 270 billion drams to the residential service customer class by applying the ratio of 44 500 customers to 49 088 customers to that amount The resulting allocated amount is 18 376 billion drams

As to the capacity amount, the table allocates 1 689 billion drams to the residential service customer class by applying the ratio of 822 MCM to 8 816 MCM to that amount The resulting allocated amount is 157 million drams

The combined asset amount for the residential service customer group is the sum of 18 376 and 0 157 billion, or 18 533 billion drams That amount appears in Column 3, Line 5

Income Statement by Class of Service

The notes that follow are an elaboration of the descriptive text in Chapter 3 dealing with the allocation procedure that was used in developing the Haygas Income Statement by Class of Service, Table 13

Note (2) -- Distribution Operating and Maintenance Expenses are usually directly proportional to the value or cost of the Distribution Assets The calculation procedure in determining the appraised asset values of the Haygas customer classes has been discussed in connection with Table C-1 and needs no repetition here These values have been transcribed from Line 13, Haygas Net Plant in Service in Table C-1 to Line 31 in Table 13 Distribution Operation Expenses in Table 13 were allocated on the Appraised Asset Values of the assets shown on Line 31 of this Table For example, Table 13 allocates the total amount of operation expenses of 1,618,471 thousand drams to the residential customer class by multiplying that number with the ratio of 21,284 47 to 36,114 74 The resulting allocated expenses for residential distribution operations is shown in Column 2, Line 5 as 953 857 thousand drams The Expenses for Distribution Maintenance (Line 12), for Depreciation (Line 16), for Property Taxes (Line 18) and for Net Profits (Line 29) also use the allocated appraised plant as the basis for allocation

Note (3) -- Social Taxes are directly related to wages Total O&M Expenses were used as a surrogate for wages These social taxes are allocated to the customer classes using the allocated Total Operation and Maintenance Expenses shown on Line 15 For example Table 13 allocates Social Taxes on Line 18 in the amount of 144 000 thousand drams to the residential service customer class by applying the ratio of 2,896,699 to 4,308,698 to that amount The resulting allocated residential sector Social Taxes appear in Column 2 Line 18, as 96 810 thousand drams

Note (4) -- Value Added Taxes are directly related to the incremental Haygas distribution costs defined as Total Revenue Requirements ("Operating Revenues") net of Gas Supply Expenses This factor is the difference between the amount on Line 1 minus the amount on Line 4 For example, the VAT for the residential service customer class is one sixth (16 6667%) of the difference between 15,115 729 and 5 411 483 thousand drams Column 2 Lines 1 and 4 The resulting VAT attributable to residential sector distribution operations appears in Column 2 Line 20 as 1,617,378 thousand drams

Note (5) -- Customer Accounts Operation Expenses are related to the number of customers For example, Table 13 allocates the expenses on Line 6 in the amount of 464,426 thousand drams to the residential service customer class by multiplying that number with the ratio of 44,500 customers to 49,088 customers, Line 14 in Table C-1 The resulting allocated amount appears in Column 2 Line 6, as 421,019 thousand drams The Uncollectible Accounts Expense, Customer Service and Informational Expenses and Sales Expenses also use the number of customers as the basis for customer class cost allocations

Note (6) – Profit taxes for each customer class were calculated on the basis of the profit allocated to each customer class The current Armenian profit tax rate of 25 0 percent was applied to the amounts shown on Line 24 For example the tax for the residential service customer class is 25% of the Gross Operating Income of that class (4 256 894 thousand drams Column 2 Line 23) The resulting amount of 1 064 223 thousand drams appear on Line 24 Column 2

Note (7) – General and Administrative Expenses relate to all operating expenses They were allocated to each customer class using the allocated Total Operations Expenses displayed on Line 11 For example, Table 13 allocates Administrative and General Expenses on Line 10 in the amount of 1,240,695 thousand drams to the residential service customer class by applying the ratio of 2,473,236 to 3,593,153 thousand drams to that amount The resulting allocated amount appears in Column 2, Line 10, as 853,994 thousand drams The Administrative and General Maintenance Expenses also are allocated using this same method

Table C-1

HAYGAS ENTERPRISE
ALLOCATION OF ASSETS TO CLASSES OF SERVICE
For the Twelve-Month Period Ending June 30, 1999
Millions of Armenian Drams

DESCRIPTION	Note	Total Amount	Facilities Held for Future Use	Residential Service	General Service	Large Volume Service	Special Contract Service	Line
COLUMN NUMBER		1	2	3	4	5	6	
DISTRIBUTION PLANT								
Land and Land Rights	(2)	46		4	3	34	5	1
Structures and Improvements	[illegible]	46		4	3	35	5	2
Mains	(5)	30,813	0	10,175	2,041	16 306	2,291	3
Pumping and Regulating Equipment	(2)	1,642		153	92	1,224	172	4
Service Lines	(6)	21,960	0	18,534	1,933	1,312	182	5
Meters	(3)	4,738		4,295	429	12	1	6
Meter Installations	(3)	3,759		3,408	341	10	1	7
Residential Regulators	(3)	1,760		1,595	160	4		8
TOTAL DISTRIBUTION PLANT		64,763	0	38,168	5,001	18,936	2 657	9
GENERAL PLANT	(1)	10,044	0	5,920	776	2,937	412	10
GROSS PLANT IN SERVICE, HAYGAS		74,808	0	44,088	5,776	21,873	3,069	11
ACCUMULATED DEPRECIATION	(4)	38,693	0	22,804	2,988	11,313	1,587	12
NET PLANT IN SERVICE, HAYGAS		36,115	0	21,284	2,789	10,560	1 482	13
Minnesota Plant Total, US $		684,586,715						14
Number of Customers		49,088		44,500	4 450	125	13	15
Peak Day Delivery - 1000 SCM		8,816		822	495	6 574	924	16
Annual Delivery 1000 SCM		1,581,915		100,000	54 254	1,090,418	337 243	17

Table C-2

HAYGAS ENTERPRISES

REVENUE REQUIREMENTS RESIDENTIAL SERVICE
Twelve Month Period Ending June 30 1999
COST CLASSIFICATION
Thousands of Armenian Drams

DESCRIPTION	NOTE	Total Amount	Customer Cost	Capacity Cost	Commodity Cost
COLUMN NUMBER		1	2	3	4
OPERATING REVENUES		15 115 676	9 043,981	520 562	5 551 133
GAS SUPPLY EXPENSE					
Gas Purchased for resale		5 320,500			5 320 500
Gas Purchased for Technological Losses		90 912			90 912
Total Gas Supply Expense		5 411,412		0	5 411 412
OPERATING AND MAINTENANCE EXPENSES					
Distribution Operation Expenses	(2)	953 857	895 009	58 848	
Customer Accounts Operation Expenses	(5)	421 019	421 019		
Uncollectible Accounts	(5)	73,404			73 404
Customer Service an Informational Expenses	(5)	103 715	103 715		
Sale Expenses	(5)	67 247	67 247		
Administrative and General Expenses	(8)	853 993	784 244	31 037	38 713
Total Operations Expenses		2 473 235	2,271,234	89 884	112 117
Distribution Maintenance Expenses	(2)	411 282	385 908	25 374	0
Administrative and General Maintenance Expenses	(8)	12 180	11 185	443	552
Total Maintenance Expenses		423 462	397 093	25 817	552
Total Operation and Maintenance Expenses		2 896 697	2 668 327	115 701	112 669
DEPRECIATION EXPENSES	(2)	708 778	665 050	43 728	0
TAXES OTHER THAN INCOME					
Custom Taxes		0			
Property Taxes	(2)	127 708	119 829	7 879	0
Social Taxes	(3)	96 810	89 178	3 867	3 765
Valued Added Taxes	(4)	1 617 377	1 507 330	86 760	23 287
Total Taxes Other Than Income		1 841 895	1 716 337	98 506	27 052
TOTAL EXPENSES BEFORE INCOME TAXES		10 858 782	5 049 714	257 935	5 551 133
GROSS OPERATING INCOME		4 256 894	3 994 267	262 627	0
PROFIT TAXES	(6)	1 064,223	998 567	65 657	0
NET OPERATING INCOME		3 192,670	2,995 700	196 970	0
INTEREST EXPENSES					
Short Term Loans		0			
Long Term Loans		0			
Total Interest Exp enses		0			
NET PROFIT	(2)	3 192 670	2,995 700	196 970	0
TOTAL DELIVERIES -- 1000 SCM per year		100 000			
APPRAISED VALUE -- Millions of Armenian Drams		21 284.47	19 971	1 313 14	
Gas Purchase Cost US $ per 1000 SCM		$106 41			
AVERAGE REVENUE PER MCM		$302 31		$10 41	$111 02
Average Customer Cost per Monthly Billing Period			$33 87		

APPENDIX D

FUTURE TARIFF CALCULATIONS

RESIDENTIAL CONSUMPTION RATES OF 500 AND 1000 MILLION SCM

Schedules F-3 and F-4
and
Variable-Fixed Residential Tariffs

ARMENIA GAS LINES 04A.XLS F 3 CELL A1

F-3 SCHEDULE

NATURAL GAS ENTERPRISES
ARMROSGASPROM PLAN
For the 12-Month Period Ending June 30, 2000

ANGE (1) INT =O&M COSTS (2) + PROP TAX 1998 VALUE (3) + DEPRECIATION (4) + RETURN=15% OF RATE BASE (5) + US OPERATING NOR

500 MILLION SCM

		ARMROS GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL
	REVENUE REQUIREMENTS				
		THOUSANDS OF ARMENIAN DRAMS			
1	OPERATING EXPENSES				
2	MATERIALS AND RAW MATERIALS	10 000	100 000	20 000	130 000
3	SALARY FUND	100 000	221 000	400 000	721 000
4	ELECTRICITY CONSUMPTION	18 000	96 000	22 000	136 000
5	FUEL CONSUMPTION	20 000	74 000	45 000	139 000
6	TECHNOLOGICAL LOSSES	0	0	0	0
7	PERSONNEL TRAINING	1 000	3 800	5 000	9 800
8	TRAVEL EXPENSES	28 000	10 000	3 400	41 400
9	RENT	1 000	0	10 000	11 000
10	CATHODIC PROTECTION	0	7 400	22 600	30 000
11	TELEPHONE CHARGES	34 000	8 000	10 000	52 000
12	COMMUNAL UTILITIES CHARGES	4 000	10 000	6 000	20 000
13	AUDIT SERVICES	20 000	9 000	17 000	46 000
14	BANKING SERVICES	332 000	6 000	11 000	349 000
15	MARKETING SERVICES	50 000	0	0	50 000
16	BAD DEBT RESERVE (USED 0 0%)	0	0	0	0
17	PROTECTION FROM NATURAL CALAMITY	3 000	46 000	33 000	82 000
18	OTHER EXPENDITURES	22 000	12 000	14 700	48 700
19	TOTAL OPERATING EXPENSES	643 000	603 200	619 700	1 865 900
20	MAINTENANCE EXPENSES				
21	VEHICLE REPAIRS AND MAINTENANCE	8 000	20 000	12 000	40 000
22	REPAIR FUND	100 000	835 428	777 018	1 712 446
23	TOTAL MAINTENANCE EXPENSES	108 000	855 428	789 018	1 752 446
24	TOTAL OPERATING AND MAINTENANCE EXPENSES	751 000	1 458 628	1 408 718	3 618 346
25	ADJUSTMENT FOR US COSTS	1,224,239	903 033	9 542 333	11 669 605
26	TOTAL ADJUSTED OPERATING EXPENSES	1 975 239	2 361 661	10 951 051	15,287 951
27	DEPRECIATION (Used 3 33 % on Gov Appraised Value)	18 681	2 743 754	1 202 630	3 965 064
28	TAXES OTHER THAN PROFIT TAXES				
29	CUSTOMS FEES	140 000	0	0	140 000
30	PROPERTY TAX (Used 0 6% on 1998 Government Valuation)	3 366	494 370	216 690	714 426
31	SOCIAL TAXES (Cap at 11 584/Employee/Month)	36 000	79 560	144 000	259 560
32	TOTAL OTHER TAXES	179 366	573 930	360 690	1 113 986
33	INTEREST ON SHORT-TERM LOANS	100 000	0	0	100 000
34	INTEREST ON LONG TERM DEBT	800 000	0	0	800 000
35	TOTAL OPERATING COSTS	3 073 286	5 679 345	12 514 371	21 267 002
36	CURRENT ASSET VALUE Millions of Drams 1998 Valuation	561	82 395	36 115	119 071
37	CURRENT ASSET VALUE $ Millions 1998 Valuation	1 12	164 79	72 23	238 14
38	DEPRECIATION (used 3 33% Based on Assumed Life Cycle of 30 Years)	3 33%	3 33%	3 33%	

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NATURAL GAS ENTERPRISES
ARMROSGASPROM PLAN
For the 12 Month Period Ending June 30 2000

		ARMROS GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL
50	Volume Received 1000 Standard Cubic Meters	2,201 132	2 201 132	2 117 489	2 201 132
51	**Losses %**	0	3 80%	1 68%	5 48%
52	Volume Delivered 1000 Standard Cubic Meters	2 201 132	2 117 489	2 081 915	2 081 915
53	Price Charged by Importer $/MCM	55 00			
54	Amount Payable to Importer $ Millions	121 062			
55	VAT, %	20%			
56	Amount Payable to State, Due to VAT, $ Millions	24 212			
57	Total Amount Import Costs plus VAT $ Million	145 275			
58	Equivalent Tariff upon Receipt of Gas $/MCM	66 000	69 473	97 332	97 332
		THOUSANDS OF ARMENIAN DRAMS			
59	**TOTAL OPERATING COSTS**	3 073 286	5 679 345	12 514 371	21 267 002
60	Rate of Return on Assets (% of Asset Base)	15 0%	15 0%	15 0%	
61	Asset Base (From Preceding Page)				
62	Profit (Return on Assets)	84 150	12 359 250	5 417 250	17 860 650
63	Profit Tax Rate %	25 0%	25 0%	25 0%	
64	Profit Before Profit Tax				
65	Amount Subject to VAT and Profit Tax (Total Revenue Requirement)	3 822 584	26 590 013	23 684 845	54 097 442
66	VAT on Company Operations	637 097	4 431 669	3 947 474	9 016 240
67	Before Tax Profit on Company Operations	112,200	16 479 000	7 223 000	23 814 200
68	Profit Tax	28 050	4 119 750	1 805 750	5 953 550
69	Profit (Check Only Not Operative)	84 150	12 359 250	5 417 250	17 860 650
		MILLIONS OF US DOLLARS			
70	Total Operating Costs	6 147	11 359	25 029	42 53
71	Profit (Return on Assets)	0 168	24 719	10 835	35 72
72	Amount Subject to VAT and Profit Tax (Additional Total Revenue Requirement)	7 645	53 180	47 370	108 19
73	VAT on Company Operations	1 274	8 863	7 895	18 03
74	Before Tax Profit on Company Operations	0 224	32 958	14 446	47 63
75	Profit Tax	0 056	8 240	3 612	11 907
76	Profit (Check Only Not Operative)	0 168	24 719	10 835	35 721
77	Total Invoice	152 920	206 100	253 470	253 470
78	Overall Tariff $/MCM	69 473	97 332	121 748	121 748
79	Incremental Tariff $/MCM	3 473	27 859	24 416	55 748
80	Total Claims $ Millions				
81	Amount Payable to Importer	121 062	0 000	0 000	121 062
82	Claims by State, Including Other Taxes	25 901	18 251	12 228	56 380
83	Operating Costs Excluding Other Taxes	5 788	10 211	24 307	40 306
84	Claims by Shareholders (After Tax Profits)	0 168	24 719	10 835	35 721
85	Total Charges	152 920	53 180	47 370	253 470
86	Armenian Charges	31 86	53 18	47 37	132 41
87	Claims % of Total Costs				
88	Claims by Importer	79 2%	0 0%	0 0%	47 8%
89	Claims by State	16 9%	34 3%	25 8%	22 2%
90	Operating Costs	3 8%	19 2%	51 3%	15 9%
91	Claims by Shareholders (After Tax Profits)	0 1%	46 5%	22 9%	14 1%
92	Total Claims	100 0%	100 0%	100 0%	100 0%
93	Claims, % of Costs Added in Armenia				
94	Claims by State	81 3%	34 3%	25 8%	42 6%
95	Operating Costs	18 2%	19 2%	51 3%	30 4%
96	Claims by Shareholders	0 5%	46 5%	22 9%	27 0%
97	Total Claims	100 0%	100 0%	100 0%	100 0%
98	Claims % of Costs Added in Armenia with State as only Shareholder				
99	Claims by State				
100	Operating Costs				
101	Total Claims				
102	Rate of Return	15 00%	15 00%	15 00%	15 00%
103	Depreciation Accrual Rate	3 33%	3 33%	3 33%	3 33%

Note Light Frames on Lines Denote Payments to or Collections by State

NATURAL GAS ENTERPRISES

ARMROSGASPROM PLAN

For the 12-Month Period Ending June 30 2002

CHANGE (1) INT =O&M COSTS (2) + PROP TAX 1998 VALUE (3) + DEPRECIATION (4) + RETURN=15% OF RATE BASE (5) + US OPERATING NORMS

1000 MILLION SCM

		ARMROS GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL
	REVENUE REQUIREMENTS	THOUSANDS OF ARMENIAN DRAMS			
1	OPERATING EXPENSES				
2	MATERIALS AND RAW MATERIALS	10 000	100 000	20 000	130 000
3	SALARY FUND	100 000	221 000	400 000	721 000
4	ELECTRICITY CONSUMPTION	18 000	96 000	22 000	136 000
5	FUEL CONSUMPTION	20 000	74 000	45 000	139 000
6	TECHNOLOGICAL LOSSES	0	0	0	0
7	PERSONNEL TRAINING	1 000	3 800	5 000	9 800
8	TRAVEL EXPENSES	28 000	10 000	3 400	41 400
9	RENT	1 000	0	10 000	11 000
10	CATHODIC PROTECTION	0	7 400	22 600	30 000
11	TELEPHONE CHARGES	34 000	8 000	10 000	52 000
12	COMMUNAL UTILITIES CHARGES	4 000	10 000	6 000	20 000
13	AUDIT SERVICES	20 000	9 000	17 000	46 000
14	BANKING SERVICES	332 000	6 000	11 000	349 000
15	MARKETING SERVICES	50 000	0	0	50 000
16	BAD DEBT RESERVE (USED 0 0%)	0	0	0	0
17	PROTECTION FROM NATURAL CALAMITY	3 000	46 000	33 000	82 000
18	OTHER EXPENDITURES	22 000	12 000	14 700	48 700
19	TOTAL OPERATING EXPENSES	643 000	603 200	619 700	1 865 900
20	MAINTENANCE EXPENSES				
21	VEHICLE REPAIRS AND MAINTENANCE	8 000	20 000	12 000	40 000
22	REPAIR FUND	100 000	835 428	777 018	1 712 446
23	TOTAL MAINTENANCE EXPENSES	108 000	855 428	789 018	1 752 446
24	TOTAL OPERATING AND MAINTENANCE EXPENSES	751 000	1 458 628	1 408 718	3 618 346
25	ADJUSTMENT FOR US COSTS	1,224 239	903 033	17 066 330	19 193 602
26	TOTAL ADJUSTED OPERATING EXPENSES	1 975,239	2 361 661	18 475 048	22 811 948
27	DEPRECIATION (Used 3 33 % on Gov Appraised Value)	18 681	2 743 754	1 202 630	3 965 064
28	TAXES OTHER THAN PROFIT TAXES				
29	CUSTOMS FEES	140 000	0	0	140 000
30	PROPERTY TAX (Used 0 6% on 1998 Government Valuation)	3 366	494 370	216 690	714 426
31	SOCIAL TAXES (Cap at 11 584/Employee/Month)	36 000	79 560	144 000	259 560
32	TOTAL OTHER TAXES	179 366	573 930	360 690	1 113 986
33	INTEREST ON SHORT-TERM LOANS	100 000	0	0	100 000
34	INTEREST ON LONG TERM DEBT	800 000	0	0	800 000
35	TOTAL OPERATING COSTS	3 073 286	5 679 345	20 038 368	28 790 998
36	CURRENT ASSET VALUE Millions of Drams 1998 Valuation	561	82 395	36 115	119 071
37	CURRENT ASSET VALUE $ Millions 1998 Valuation	1 12	164 79	72.23	238 14
38	DEPRECIATION (used 3 33% Based on Assumed Life Cycle of 30 Years)	3 33%	3 33%	3 33%	

ARMENIA GAS LINES 04A.XLS F 4 CELL A5

F-4 SCHEDULE CONTINUED

NATURAL GAS ENTERPRISES
ARMROSGASPROM PLAN
For the 12 Month Period Ending June 30 2002

		ARMROS GASPROM	TRANSGAS Pipeline	HAYGAS Distributor	TOTAL
50	Volume Received 1000 Standard Cubic Meters	2 729 763	2 729 763	2 626 032	2 729 763
51	Losses %	0	3 80%	1 68%	5 48%
52	Volume Delivered 1000 Standard Cubic Meters	2 729 763	2 626 032	2 581 915	2 581 915
53	Price Charged by Importer $/MCM	55 00			
54	Amount Payable to Importer $ Millions	150 137			
55	VAT, %	20%			
56	Amount Payable to State, Due to VAT, $ Millions	30 027			
57	Total Amount Import Costs plus VAT $ Million	180 164			
58	Equivalent Tariff upon Receipt of Gas $/MCM	66 000	68 801	91 769	91 769
		THOUSANDS OF ARMENIAN DRAMS			
59	**TOTAL OPERATING COSTS**	3 073 286	5 679 345	20 038 368	28 790 996
60	Rate of Return on Assets (% of Asset Base)	15 0%	15 0%	15 0%	
61	Asset Base (From Preceding Page)				
62	Profit (Return on Assets)	84 150	12 359 250	5 417 250	17 860 650
63	Profit Tax Rate %	25 0%	25 0%	25 0%	
64	Profit Before Profit Tax				
65	Amount Subject to VAT and Profit Tax (Total Revenue Requirement)	3 822 584	26 590 013	32 713 641	63 126 238
66	VAT on Company Operations	637 097	4 431 669	5 452 274	10 521 040
67	Before Tax Profit on Company Operations	112,200	16 479 000	7 223 000	23 814 200
68	Profit Tax	28 050	4 119 750	1 805 750	5 953 550
69	Profit (Check Only Not Operative)	84 150	12 359 250	5 417 250	17 860 650
		MILLIONS OF US DOLLARS			
70	Total Operating Costs	6 147	11 359	40 077	57 58
71	Profit (Return on Assets)	0 168	24 719	10 835	35 72
72	Amount Subject to VAT and Profit Tax (Additional Total Revenue Requirement)	7 645	53 180	65 427	126 25
73	VAT on Company Operations	1 274	8 863	10 905	21 04
74	Before Tax Profit on Company Operations	0 224	32 958	14 446	47 63
75	Profit Tax	0 056	8 240	3 612	11 907
76	Profit (Check Only Not Operative)	0 168	24 719	10 835	35 721
77	Total Invoice	187 810	240 990	306 417	306 417
78	Overall Tariff $/MCM	68 801	91 769	118 678	118 678
79	Incremental Tariff $/MCM	2 801	22 969	26 909	52 678
80	Total Claims $ Millions				
81	Amount Payable to Importer	150 137	0 000	0 000	150 137
82	Claims by State Including Other Taxes	31 716	18 251	15 237	65 205
83	Operating Costs Excluding Other Taxes	5 788	10 211	39 355	55 354
84	Claims by Shareholders (After Tax Profits)	0 168	24 719	10 835	35 721
85	Total Charges	187 810	53 180	65 427	306 417
86	Armenian Charges	37 67	53 18	65 43	156 28
87	Claims % of Total Costs				
88	Claims by Importer	79 9%	0 0%	0 0%	49 0%
89	Claims by State	16 9%	34 3%	23 3%	21 3%
90	Operating Costs	3 1%	19 2%	60 2%	18 1%
91	Claims by Shareholders (After Tax Profits)	0 1%	46 5%	16 6%	11 7%
92	Total Claims	100 0%	100 0%	100 0%	100 0%
93	Claims % of Costs Added in Armenia				
94	Claims by State	84 2%	34 3%	23 3%	41 7%
95	Operating Costs	15 4%	19 2%	60 2%	35 4%
96	Claims by Shareholders	0 4%	46 5%	16 6%	22 9%
97	Total Claims	100 0%	100 0%	100 0%	100 0%
98	Claims % of Costs Added in Armenia with State as only Shareholder				
99	Claims by State				
100	Operating Costs				
101	Total Claims				
102	Rate of Return	15 00%	15 00%	15 00%	15 00%
103	Depreciation Accrual Rate	3 33%	3 33%	3 33%	3 33%

Note Light Frames on Lines Denote Payments to or Collections by State

Table D-1

HAYGAS ENTERPRISE

INCOME STATEMENT 500 MILLION SCM/YEAR
BY CLASS OF SERVICE
For the 12-Month Period Ending June 30 2000

Thousands of Armenian Drams

DESCRIPTION	NOTE	Total Amount	Residential Service	General Service	Large Volume Service	Special Contract Service	Line
COLUMN NUMBER		1	2	3	4	5	
OPERATING REVENUES		126 734 534	44 360 085	3 452 880	60 673 086	18 248 483	1
GAS SUPPLY EXPENSE							
Gas Purchased for resale		101 318 475	24 333 000	2 818 491	56 647 224	17 519 760	2
Gas Purchased for Technological Losses		1 731 235	415 779	48 160	967 935	299 361	3
Total Gas Supply Expense		103 049 711	24 748 779	2 866 651	57 615 159	17 819 121	4
OPERATING AND MAINTENANCE EXPENSES							
Distribution Operation Expenses	(2)	1 618 471	1 172 503	45 752	350 921	49 295	5
Customer Accounts Operation Expenses	(5)	3 439 850	3 370 352	67 407	1 893	197	6
Uncollectible Accounts	(5)	599 728	587 611	11 752	330	34	7
Customer Service an Informational Expenses	(5)	847 379	830 259	16 605	466	49	8
Sale Expenses	(5)	549 428	538 328	10 767	302	31	9
Administrative and General Expenses	(8)	3 153 366	2 904 934	68 067	158 192	22 173	10
Total Operations Expenses		10 208 222	9 403 987	220 350	512 105	71 779	11
Distribution Maintenance Expenses	(2)	697 849	505 557	19 727	151 309	21 255	12
Administrative and General Maintenance Expenses	(8)	44 973	41 430	971	2 256	316	13
Total Maintenance Expenses		742 822	546 988	20 698	153 566	21 571	14
Total Operation and Maintenance Expenses		10 951 044	9 950 975	241 048	665 671	93 350	15
DEPRECIATION EXPENSES	(2)	1 202 630	871 247	33 997	260 757	36 629	16
TAXES OTHER THAN INCOME							
Custom Taxes		0					17
Property Taxes	(2)	218 690	156 981	6 126	46 983	6 600	18
Social Taxes	(3)	144 000	130 850	3 170	8 753	1 227	19
Valued Added Taxes	(4)	3 947 471	3 268 551	97 705	509 655	71 560	20
Total Taxes Other Than Income		4 308 161	3 556 382	107 000	565 391	79 388	21
TOTAL EXPENSES BEFORE INCOME TAXES		119 511 545	39 127 383	3 248 696	59 106 978	18 028 488	22
GROSS OPERATING INCOME		7 222 989	5 232 702	204 184	1 566 108	219 995	23
PROFIT TAXES	(6)	1 805 747	1 308 176	51 046	391 527	54 999	24
NET OPERATING INCOME		5 417 242	3 924 527	153 138	1 174 581	164 996	25
INTEREST EXPENSES							
Short Term Loans		0					26
Long Term Loans		0					27
Total Interest Exp enses		0					28
NET PROFIT	(2)	5 417 242	3 924 527	153 138	1 174 581	164 996	29
TOTAL DELIVERIES 1000 SCM per year		2 081 915					30
APPRAISED VALUE -- Millions of Armenian Drams		36 114 94	26 163 51	1 020 92	7 830 54	1 099 97	31
Gas Purchase cost US $ per 1000 SCM		$97 33					32
769							
AVERAGE REVENUE PER MCM		$121 75	$177 44	$119 24	$104 25	$101 38	

Table D-2

HAYGAS ENTERPRISE

INCOME STATEMENT - 1000 MILLION SCM/YEAR
BY CLASS OF SERVICE
For the 12-Month Period Ending June 30 2002

Thousands of Armenian Drams

DESCRIPTION	NOTE	Total Amount	Residential Service	General Service	Large Volume Service	Special Contract Service	Line
COLUMN NUMBER		1	2	3	4	5	
OPERATING REVENUES		153 207,801	76 318 022	3 145 154	56 621 152	17 123 473	1
GAS SUPPLY EXPENSE							
Gas Purchased for resale		118 469 879	45 884 500	2 657 401	53 409 558	16 518 420	2
Gas Purchased for Technological Losses		2,024 302	784 031	45 407	912 612	282 251	3
Total Gas Supply Expense		120 494 181	46 668 531	2 702 808	54 322 170	16 800 671	4
OPERATING AND MAINTENANCE EXPENSES							
Distribution Operation Expenses	(2)	1 618 471	1,286 882	29 700	264 700	37 189	5
Customer Accounts Operation Expenses	(5)	6 810 202	6 740 704	67 407	1 893	197	6
Uncollectible Accounts	(5)	1 187 339	1 175 223	11 752	330	34	7
Customer Service an Informational Expenses	(5)	1 677 838	1 660 518	16 605	466	49	8
Sale Expenses	(5)	1 087 756	1 076 655	10 767	302	31	9
Administrative and General Expenses	(8)	5 319 908	5 130 242	58 534	115 019	16 113	10
Total Operations Expenses		17 701 314	17 070 224	194 765	382 712	53 612	11
Distribution Maintenance Expenses	(2)	697 849	554 875	12 806	114 133	16 035	12
Administrative and General Maintenance Expenses	(8)	75 873	73 168	835	1 640	230	13
Total Maintenance Expenses		773 722	628 043	13 641	115 773	16 265	14
Total Operation and Maintenance Expenses		18 475 035	17 698 267	208 406	498 485	69 877	15
DEPRECIATION EXPENSES	(2)	1 202 630	956 238	22 069	196 690	27 634	16
TAXES OTHER THAN INCOME							
Custom Taxes		0					17
Property Taxes	(2)	216 690	172,295	3 976	35 440	4 979	18
Social Taxes	(3)	144 000	137 946	1 624	3 885	545	19
Valued Added Taxes	(4)	5 452 270	4 941 582	73 724	383 164	53 800	20
Total Taxes Other Than Income		5 812 960	5 251 822	79 325	422 488	59 324	21
TOTAL EXPENSES BEFORE INCOME TAXES		145 984 807	70 574 859	3 012 608	55 439 834	16 957 506	22
GROSS OPERATING INCOME		7 222 994	5 743 163	132 546	1 181 318	165 967	23
PROFIT TAXES	(6)	1 805 749	1 435 791	33 136	295 329	41 492	24
NET OPERATING INCOME		5 417 246	4 307 372	99 409	885 988	124 476	25
INTEREST EXPENSES							
Short Term Loans		0					26
Long Term Loans		0					27
Total Interest Exp enses		0					28
NET PROFIT	(2)	5 417 246	4 307 372	99 409	885 988	124 476	29
TOTAL DELIVERIES -- 1000 SCM per year		2 581 915					30
APPRAISED VALUE -- Millions of Armenian Drams		36 114 97	28 715 82	662 73	5 906 59	829 84	31
Gas purchase cost US $ per 1000 SCM		$91 77					
AVERAGE REVENUE PER MCM	769	$118 68	$152 64	$108 61	$97 29	$95 13	

Table D-3

HAYGAS ENTERPRISES

REVENUE REQUIREMENTS RESIDENTIAL SERVICE 500 MILLION SCM/YEAR
Twelve Month Period Ending June 30 2000
COST CLASSIFICATION
Thousands of Armenian Drams

DESCRIPTION	NOTE	Total Amount	Customer Cost	Capacity Cost	Commodity Cost
COLUMN NUMBER		1	2	3	4
OPERATING REVENUES		44 360 085	16 788 265	1 784 757	25 787 063
GAS SUPPLY EXPENSE					
Gas Purchased for resale		24 333 000			24 333 000
Gas Purchased for Technological Losses		415 779			415 779
Total Gas Supply Expense		24 748 779		0	24 748 779
OPERATING AND MAINTENANCE EXPENSES					
Distribution Operation Expenses	(2)	1 172 503	967 333	205 170	
Customer Accounts Operation Expenses	(5)	3 370 352	3 370 352		
Uncollectible Accounts	(5)	587 611			587 611
Customer Service an Informational Expenses	(5)	830 259	830 259		
Sale Expenses	(5)	538 328	538 328		
Administrative and General Expenses	(8)	2 904 934	2 550 579	91 706	262 649
Total Operations Expenses		9 403 987	8 256 851	296 876	850 261
Distribution Maintenance Expenses	(2)	505 557	417 093	88 465	0
Administrative and General Maintenance Expenses	(8)	41 430	36 376	1 308	3 746
Total Maintenance Expenses		546 988	453 469	89 773	3 746
Total Operation and Maintenance Expenses		9 950 975	8 710 320	386 649	854 007
DEPRECIATION EXPENSES	(2)	871 247	718 792	152 455	0
TAXES OTHER THAN INCOME					
Custom Taxes		0			
Property Taxes	(2)	156 981	129 512	27 469	0
Social Taxes	(3)	130 850	114 536	5 084	11 230
Valued Added Taxes	(4)	3 268 551	2 798 044	297 459	173 047
Total Taxes Other Than Income		3 556 382	3 042 092	330 013	184 277
TOTAL EXPENSES BEFORE INCOME TAXES		39 127 383	12 471 204	869 116	25 787 063
GROSS OPERATING INCOME		5 232 702	4 317 061	915 641	0
PROFIT TAXES	(6)	1 308 176	1 079 265	228 910	0
NET OPERATING INCOME		3 924 527	3 237 796	686 731	0
INTEREST EXPENSES					
Short Term Loans		0			
Long Term Loans		0			
Total Interest Exp enses		0			
NET PROFIT	(2)	3 924 527	3 237 796	686 731	0
TOTAL DELIVERIES -- 1000 SCM per year		500 000			
APPRAISED VALUE -- Millions of Armenian Drams		26 163 51	21 585	4 578 20	
Gas Purchase Cost US $ per 1000 SCM		$97 33			
AVERAGE REVENUE PER MCM		$177 44		$7 14	$103 15
Average Customer Cost per Monthly Billing Period			$12 58		
Monthly Marginal Customer Cost per Customer			$7 25		

Table D-4

HAYGAS ENTERPRISES

REVENUE REQUIREMENTS RESIDENTIAL SERVICE 1000 MILLION SCM/YEAR
Twelve Month Period Ending June 30 2002
COST CLASSIFICATION
Thousands of Armenian Drams

DESCRIPTION	NOTE	Total Amount	Customer Cost	Capacity Cost	Commodity Cost
COLUMN NUMBER		1	2	3	4
OPERATING REVENUES		76 318 022	24 925 306	2 683 544	48 709 171
GAS SUPPLY EXPENSE					
Gas Purchased for resale		45 884 500			45 884 500
Gas Purchased for Technological Losses		784 031			784 031
Total Gas Supply Expense		46 668 531		0	46 668 531
OPERATING AND MAINTENANCE EXPENSES					
Distribution Operation Expenses	(2)	1 286 882	977 204	309 678	
Customer Accounts Operation Expenses	(5)	6 740 704	6 740 704		
Uncollectible Accounts	(5)	1 175 223			1 175 223
Customer Service an Informational Expenses	(5)	1 660 518	1 660 518		
Sale Expenses	(5)	1 076 655	1 076 655		
Administrative and General Expenses	(8)	5 130 242	4 492 226	133 059	504 957
Total Operations Expenses		17 070 224	14 947 307	442 737	1 680 180
Distribution Maintenance Expenses	(2)	554 875	421 349	133 526	0
Administrative and General Maintenance Expenses	(8)	73 168	64 068	1 898	7 202
Total Maintenance Expenses		628 043	485 417	135 424	7 202
Total Operation and Maintenance Expenses		17 698 267	15 432 725	578 161	1 687 381
DEPRECIATION EXPENSES	(2)	956 238	726 127	230 111	0
TAXES OTHER THAN INCOME					
Custom Taxes		0			
Property Taxes	(2)	172 295	130 834	41 461	0
Social Taxes	(3)	137 946	120 287	4 506	13 152
Valued Added Taxes	(4)	4 941 582	4 154 218	447 257	340 107
Total Taxes Other Than Income		5 251 822	4 405 339	493 225	353 259
TOTAL EXPENSES BEFORE INCOME TAXES		70 574 859	20 564 190	1 301 497	48 709 171
GROSS OPERATING INCOME		5 743 163	4 361 116	1 382 047	0
PROFIT TAXES	(6)	1 435 791	1 090 279	345 512	0
NET OPERATING INCOME		4 307 372	3 270 837	1 036 535	0
INTEREST EXPENSES					
Short Term Loans		0			
Long Term Loans		0			
Total Interest Exp enses		0			
NET PROFIT	(2)	4 307 372	3 270 837	1 036 535	0
TOTAL DELIVERIES – 1000 SCM per year		1 000 000			
APPRAISED VALUE – Millions of Armenian Drams		28 715 82	21 806	6 910 23	
Gas Purchase Cost US $ per 1000 SCM		$91 77			
AVERAGE REVENUE PER MCM		$152 64		$5 37	$97 42
Average Customer Cost per Monthly Billing Period			$9 34		
Monthly Marginal Customer Cost per Customer			$6 10		