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HIGH-BTU GAS SUPPLY SYSTEMS: THE CHARACTERIZATION AND SOCIAL COST OF SELECTED OPTIONS FOR PROVIDING GAS TO A MIDWESTERN TERMINUS

by

M. E. Samsa, K. A. Hub, and A. R. Evans

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Energy and Environmental Systems Division

October 1977

FOREWORD

This assessment of future high-Btu gas supply options is one of several technology and social cost assessment programs undertaken by the Energy and Environmental Systems Division of Argonne National Laboratory. The work reported here was conducted under sponsorship of the Energy Research and Development Administration. Activities and responsibilities of the sponsor correspond to those now in the U.S. Department of Energy, Office of Technology Impacts, Division of Regional Assessments.

The objective of this study of gas supply systems was to prepare an initial evaluation of the social costs for providing high-Btu gas to a region of the United States during the 1985-1990 period by selected options. The study provides information that is applicable to the selection of future gas supply options for that region. It also provides a basis for continued and expanded analysis of gas supply options for other regions and the assessment of several advanced technologies and related policy considerations.

Specifically, the assessment considers both the internal and external costs of systems supplying equivalent quantities of high-Btu gas for consumption in the Midwest. Impact assessment of all activities leading to "city gate" delivery were included; excluded were assessments of impacts of local distribution to consumers since these remain substantially unchanged. Also excluded were assessments of non-gas energy supply alternatives for these consumers. Specific technology options and energy-source locations were selected. These supply alternatives were not intended to portray political or economic rivals, but rather to be representative of energy sources that may be technologically viable in the 1985-1990 period. Impacts associated with the extraction, production or importation activities of each of the supply systems would remain largely unchanged if the product gas were assumed to supply another region. The impacts associated with gas transmission would be altered, however, since these are dependent upon the pipeline's location, distance, and whether a new or existing pipeline is used.

The assessment is based on a synthesis of data from the literature with suitable adjustments and approximations made where necessary. This work was performed by ANL and a subcontractor, Sargent and Lundy Engineers. The final analyses and descrptions are the responsibility of the ANL authors.

EXECUTIVE SUMMARY

OBJECTIVE

Over one-fourth of all domestic energy consumption derives from natural gas. In 1975 a total of 20.0 trillion cubic feet (tcf), or over 20 quads of energy, were provided by this source. However, recent declining trends in new gas reserve additions and increasing supply curtailments dramatize the growing national concern over the adequancy of future domestic natural gas resources.

Several high-Btu gas supply system alternatives show technological viability for the near future, 1985-1990. The choice of supply systems for specific applications would involve an evaluation of the expected social benefits and costs associated with future options. The primary objective of this study is to provide a comparative social cost assessment of four options for supplying high-Btu gas to the Midwest. Technologies considered in this assessment include production of nonassociated natural gas (produced without significant quantities of oil) from the Gulf of Mexico Outer Continental Shelf (OCS), importation of liquified natural gas (LNG), and first generation Lurgi gasification of domestic lignite and bituminous coals. Pipeline transportation from the point of production or importation to a representative terminus in the Midwest was also included.

The social benefit from each of these systems is the supply of an increment of high-Btu gas to the Midwest. This assessment compares alternative systems for providing this supply in the 1985-1990 period on the basis of both internal and external costs. Internal costs are those dollar costs which compose the final sale price of the high-Btu gas; external costs are those costs paid by members of society in ways that may bear little relationship to their use of the product. The inhalation of air pollutants emitted from gas production activities is an example of the latter. Where possible these costs are quantified. In other cases, where costs assignable to an activity are not quantifiable, a qualitative comparison is made. Due to the restrictions on time and effort the assessment of external costs was limited to primary externalities. (It is recognized that a more complete assessment would include secondary and higher-order external costs, i.e., external costs that emanate from the activities associated with the capital and operating goods industries that supply the production process). Nor does this study

address the problems associated with opportunity costs and future optimum use of high-Btu gas supplies. Nevertheless, the information provided here could well aid future assessments of such problems.

METHODOLOGY

A reference system methodology was selected to examine and compare the social costs associated with the four alternative high-Btu gas supply technologies. In the reference system approach, supply units of similar capacities, and thus nearly equal primary social benefits, are defined and characterized for each alternative. Associated quantifiable internal and external costs are then determined. In this study reference supply system capacities are chosen to represent incremental supply additions; social costs are quantified and compared at a level of magnitude typical of incremental capacity additions.

Each supply increment and its costs is described maintaining internal consistency while reflecting those characteristics representative of the 1985-1990 technologies. System characterizations are based upon the assumption that future national demand for high-Btu gas will be in reasonable balance with supply at a level about equal to current use. All systems and social costs are defined within the same set of social boundaries, namely, the U.S. society, including its populace and environment as well as its governmental and socioeconomic infrastructures. Thus, the reference system methodology provides a technique for normalizing and comparing social costs.

REFERENCE SUPPLY SYSTEMS

A net production output of 250 million cubic feet per day (MMcfd)* served as the basis for defining the alternative reference production systems. Gas recovery from the Gulf OCS was assumed to be off the central coast of Louisiana. Imported LNG was assumed to be received at the Louisiana Gulf Coast with the LNG supply originating in Algeria. The lignite gasification system was located in the Mercer/Dunn County area of North Dakota, and the bituminous gasification system sited in Fulton County, Illinois. Each system was assumed to be connected to a representative Midwestern terminus in the

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*NB: Unit measures follow gas industry usage; MMcfd = million cubic feet per day; MMBtu = million Btu.

Chicago-Northern Indiana area by a designated pipeline designed for transportation of the production capacity. The locations of the energy supply-demand centers and the technologies are hypothetical in that they do not necessarily represent a situation in which the choice of a preferred system is being made. Rather, these locations were chosen as representative energy sources that may be viable in the 1985-1990 period.

Each alternative supply system is described in terms of its production site and transmission facilities to a representative Midwestern terminus in the Chicago-Northern Indiana area. Social costs result from the construction and operation of these facilities. Impacts associated with the final distribution of gas to the customer are not measurably different than the costs and risks that exist from today's gas distribution systems. Thus the final distribution of gas has not been included in the system definitions and the associated costs have not been quantified.

The normalized social costs resulting from gas extraction, production or importation are largely independent of the locale in which the gas is ultimately consumed, but rather are characteristic of the general site assumed for these activities. Impacts associated with gas transmission from the extraction, production or importation sites to the consumption area, however, are strongly dependent upon the pipeline's location, distance, and whether a new or existing pipeline is used. Thus, gas transmission is treated as an add-on system with its own set of social costs which combine with the social costs from the production activities.

Deliverable energy from each system is sufficient to satisfy the requirements of an average U.S. community of 900-950 thousand persons, or is equivalent to 12% of the average daily natural gas consumption in the Chicago-Northern Indiana area. Table S.1 summarizes the salient design parameters that characterize the reference supply systems. Characteristics are based on a synthesis of data from the literature with suitable adjustments and approximations made where necessary.

SOCIAL COSTS

The following categories of impacts (social costs) were considered in the assessment:

Table S.1. Characteristics of 250 MMcfd High-Btu Gas Reference Supply Systems and Pipelines

Offshore Production

Product Gas Heating Value (Btu/cf):	1,024
Extraction Operations:	
Production Units	3
Gross Withdrawal (MMcfd)	285
Lease Fuel Use (MMcfd)	12
Delivered at Process Plant (MMcfd)	273
Operating Personnel	93
Processing Plant:	
Design Capacity (MMcfd)	374
Fuel, Vent, Flare, Losses (MMcfd)	10
Extraction Losses (MMcfd)	13
Operating Personnel	54
Pipeline:	
Type	Existing
Distance (mi)	900
Operating Personnel	110
Energy Balance (10^9Btu/d):	
Gross Withdrawal	309.55
Less System Losses and Uses:	
Vent, Flare, Unaccounted for	2.18
Lease and Plant Fuel	21.05
Extraction Losses	30.32
Pipeline Fuel	3.48
Pipeline Losses	2.26
Net Delivery	250.26

LNG Importation

Product Gas Heating Value (Btu/cf):	1,015
Receiving and Regasification Terminal:	
Regasification Units	4
Exported LNG (m^3/d)	12,295
Delivered LNG (m^3/d)	11,617
Auxiliary LNG Feed (m^3/d)	290
Operating Personnel	30
Transportation Vessels (Each):	
Number of Vessels	3
Design Capacity (m^3)	130,000
Deliveries Per Year	12
Operating Personnel	33
Pipeline:	
Type	Existing
Distance (mi)	900
Operating Personnel	110
Energy Balance (10^9Btu/d):	
Net LNG Exported	275.46
Less System Losses and Uses:	
Transportation Boil-off	15.20
Regasifier Fuel	4.96
Other Plant Uses	1.55
Pipeline Fuel	3.48
Pipeline Losses	2.24
Net Delivery	248.03

Lignite Gasification

Product Gas Heating Value (Btu/cf):	970
Gasification Plant:	
Gasification Trains	32
Gasifier Coal Feed (tons/d)	26,000
Auxiliary Coal Feed (tons/d)	7,540
Process Steam (tons/d)	21,740
Operating Personnel	750
Surface Mine:	
Capacity (tons/d)	33,540
Heating Value (Btu/lb)	6,820
Seam Thickness (ft)	20
Operating Personnel	375
Pipeline:	
Type	New
Distance (mi)	900
Operating Personnel	110
Energy Balance (10^9Btu/d):	
Lignite Feed	457.49
Less System Losses and Uses:	
Steam Generation	85.04
Electrical Generation	17.80
Byproducts	112.15
Pipeline Fuel	3.48
Pipeline Losses	2.14
Net Delivery	236.88

Bituminous Gasification

Product Gas Heating Value (Btu/cf):	970
Gasification Plant:	
Gasification Trains	23
Gasifier Coal Feed (tons/d)	16,860
Auxiliary Coal Feed (tons/d)	5,570
Process Steam (tons/d)	27,800
Operating Personnel	750
Surface Mine:	
Capacity (tons/d)	22,430
Heating Value (Btu/lb)	11,000
Seam Thickness (ft)	8
Operating Personnel	300
Pipeline:	
Type	New
Distance (mi)	180
Operating Personnel	22
Energy Balance (10^9Btu/d):	
Bituminous Feed	493.46
Less System Losses and Uses:	
Steam Generation	101.31
Electrical Generation	21.23
Byproducts	128.42
Pipeline Fuel	0.00
Pipeline Losses	0.43
Net Delivery	242.07

Conventional dollar costs (internal costs)

- Capital Costs
- Operating Costs

Resource use

- Mineral
- Land
- Air
- Water
- Manpower
- Capital resources

Environmental consequences

- Effluents and other physical impacts
- Alteration of ambient conditions of air, water, and land
- Effects on natural systems
- Effects on property and economic activities

Human health and safety

- Effects on the general public
  - Effluent-induced morbidity and mortality
  - Accidents
- Effects on occupational personnel
  - Exposure to effluents
  - Accidents

Socioeconomic consequences

- Employment for construction and operation
- Induced and secondary employment
- Demographic change
- Impact on local housing and public services
- Fiscal and administrative impacts
- Sociocultural change

Internal costs are exhibited as conventional dollar costs associated with the construction and operation of the gas supply alternatives. The assessment presents these costs to provide reference points for the comparison of external costs and to illustrate the relative economic competitiveness between the alternatives.

Although resource inputs were included in determining conventional dollar costs, they were also examined as physical quantities with finite availability. Mineral resource use consists primarily of direct feed material utilized in supplying gas for transmission and ultimate consumption. Land requirements were addressed in three forms: acre-years required during

construction or development, acres necessary to support the direct supply activities over an assumed economic lifetime, and acres per year disrupted to support supply activities. The use of littoral and offshore regions has also been included as land use in this assessment. Water requirements refer to consumptive uses of this resource. Direct manpower requirements were assessed for both the construction and operational phases of each of the alternatives. Capital resources refer to the investment required in comparison with the economic resources of the entities financing the energy system.

Environmental residuals of the construction and operation of the energy systems affect air, water, and land. The majority of residuals were quantified in physical units of residuals produced per unit of high-Btu gas supplied by the reference energy systems. The systems were assessed generically. Where local environmental conditions are known, ambient concentrations of air and water pollutants could be calculated, and the effects on natural systems and consequences to property and economic activity could be assessed. In this work, however, considerations were limited to effluents produced by the reference systems.

With the absence of quantitative dose-response relationships for human exposure to environmental stresses or noxious agents, the treatment of health effects in this study takes the form of a general discussion of their nature. Some discussion is also presented on the uncertainties surrounding the deposition and ultimate fate of trace elements, particularly as a result of the coal gasification processes and offshore drilling operations.

Regional socioeconomic impacts were estimated on the basis of direct employment requirements. A socioeconomic impact assessment methodology developed at Argonne National Laboratory was utilized. The assessment of these impacts was restricted to direct, indirect, and income-induced employment and population changes in the general vicinity of the development sites. Analysis of impacts on housing and public services are dependent on site-specific conditions and were thus not addressed.

Table S.2 highlights and compares some of the social costs associated with the reference supply systems. The reader is cautioned that these results

Table S.2. Social Costs for 250 MMcfd Reference Gas Supply Systems and Pipelines

	Offshore Production	LNG Importation	Lignite Gasification	Bituminous Gasification
Construction Costs (million 1975 dollars)				
Production System	627.10	609.20	1,138.70	1,255.30
Pipeline	--	--	218.20	40.80
Annual Charges (million 1975 dollars)				
Production Unit Capital	137.96	73.10	136.64	150.64
Levelized O&M and Production Royalties[a]	8.50	24.21	106.33	96.85
Levelized Foreign Gas Purchases	--	165.00	--	--
TOTAL Production Charges	146.46	262.31	242.97	247.49
Transmission Charges	30.58	30.58	32.93	6.25
TOTAL CHARGES	177.04	292.89	275.90	253.74
Unit Delivered Cost ($/MMBtu)	1.93	3.23	3.20	2.87
Unit Production Cost ($/MMBtu)	1.57	2.83	2.74	2.79
Air Residuals (tons/yr)				
Particulates	60	40	2,900	2,000
NO_x	2,800	1,700	28,900	20,600
SO_x	2	40	16,100	25,000
Hydrocarbons	29,800	17,000	20,000	5,600
Water Residuals (tons/yr)				
Total Solids	70,600	~0	(b)	9,100
Organics	--	10	(b)	3,700
Solid Wastes (tons/yr)	130	70	1,000,000	1,000,000
Consumptive Water Use (10^6 gal/year)	3	6	6,200	6,200
Land Use				
Site Area (acres)	160	200	1,800	1,800
Annual Disruption (acres/year)	0	0	350	590
Annual Occupational Accident Rates				
Disabling Injuries	5.82	4.92	29.07	23.97
Fatalities	0.19	0.10	0.63	0.53
Productivity Losses (man-days)	1,710	1,040	5,670	4,690
Other Social Costs:	Offshore Hydrocarbon Spillage	Reliance on Foreign Energy Supplies LNG Hazards	Trace Metals & Carcinogens Socioeconomic Impact	Trace Metals & Carcinogens

(a) Production unit royalties apply only to coal extraction activities; offshore royalties are 16.7% of gross revenues and are included in the annual charge rate and O&M charges.

(b) Assumes on-site disposal to evaporation on ponds.

should be used only with reference to the assumptions and rationale presented in the full report. Of particular note is Appendix D which outlines the economic cost methodology. Also, coal gasification system costs assume gas utility ownership of supporting mine operations. Results vary significantly if costs are determined using 1985 projected market prices (in 1975 dollars) of $6.50/ton for lignite and $11.70/ton for bituminous coal, rather than the utility owned pass-through costs of $3.90/ton and $5.20/ton respectively. Under these assumptions delivered costs for gas from the lignite and bituminous gasification systems are both $3.81/MMBtu. These costs are not only equal but significantly greater than those shown in Table S.2.

Social costs that are recognized but not quantified are also indicated in Table S.2. The social cost of increased reliance on foreign energy suppliers, the hazards associated with LNG transportation and handling, and the unknown fate and consequence of trace metals and carcinogenic compound emissions are examples of these costs, which are discussed qualitatively in the report.

DIRECTIONS FOR FUTURE ACTIVITIES

This social cost assessment provides a solid starting point for future gas supply-demand assessments. There are many possible directions that these activities might take. Included are evaluations of other, more advanced, gas supply sources and technologies, other gas consumption regions, the integration of higher-order impacts, a comparative social cost assessment of high-Btu centralized versus low-Btu decentralized coal gasification, and others. Whereas this initial study was conducted with a broad perspective toward impact quantification and comparison, future user-directed assessments might emphasize and focus on a more limited set of issues of interest to the user.

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UNITS OF MEASURE

ac	acre
bbl	barrel
BBtu	billion (10^9) British thermal units
bcf	billion (10^9) standard* cubic feet
°C	degree Celsius
°F	degree Fahrenheit
ft	feet
gal	gallon
gpm	gallon per minute
hp	horsepower
in	inch
kWh	Kilowatt-hour
l	liter
lb	pound
m^3_ℓ	cubic meter of liquid
mg	milligram
mi	mile
mo	month
MW	megawatt electric
MMBtu	million (10^6) British thermal units
Mcf	thousand (10^3) standard* cubic feet
MMcf	million (10^6) standard* cubic feet
Mcfd	thousand (10^3) standard* cubic feet per day
MMcfd	million (10^6) standard* cubic feet per day
psia	pounds per square inch, absolute
psig	pounds per square inch, gauge
°R	degree Rankine
tcf	trillion (10^{12}) standard* cubic feet
yr	year

*Standard gaseous volume measures follow U.S. natural gas industry convention and are based on a standard pressure base of 14.73 psia, and a standard temperature of 60°F.

ABBREVIATIONS

AAPG	American Association of Petroleum Geologists
AGA	American Gas Association
ANG	American Natural Gas Company
API	American Petroleum Institute
BLM	Bureau of Land Management
BOM	Bureau of Mines
BOP	blowout preventer
CDS	construction differential subsidy
DEIS	Draft Environmental Impact Statement
DOI	U.S. Department of Interior
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
ERC	Energy Resource Council
ERDA	Energy Research and Development Administration
FEA	Federal Energy Administration
FEIS	Final Environmental Impact Statement
FPC	Federal Power Commission
FTC	Federal Trade Commission
LNG	liquefied natural gas
NDL	North Dakota lignite
NEB	Canadian National Energy Board
NEP	National Energy Plan
NEPA	National Environmental Policy Act
NSPS	New Source Performance Standards
O&M	operation and maintenance
OCS	outer continental shelf
OTA	Office of Technology Assessment
SFCPES	Synthetic Fuels Commercialization Program Environmental Statement
SIB	Southern Illinois bituminous coal
SNG	synthetic "natural" gas
USGS	U.S. Geological Survey
WESCO	Western Coal Gasification Company

HIGH-BTU GAS SUPPLY SYSTEMS: THE CHARACTERIZATION AND SOCIAL COST OF SELECTED OPTIONS FOR PROVIDING GAS TO A MIDWESTERN TERMINUS

by

M.E. Samsa, K.A. Hub, and A.R. Evans

ABSTRACT

This study identifies and compares the social costs of alternative methods of supplying incremental quantities of pipeline-quality gas to the Chicago-Northern Indiana area in the 1985-1990 time period: increased offshore production of nonassociated natural gas, imported liquefied natural gas, and first-generation Lurgi gasification of North Dakota lignite and southern Illinois bituminous coal. Reference systems, each supplying 250 million cubic feet of gas per day, are defined and characterized to allow comparison of the four options on an equivalent basis. The social costs emphasized are resource use, environmental residuals, conventional construction and operating costs, socio-economic impacts, and human health and safety impacts. Where possible, the social costs are quantified and presented side by side for the four reference systems.

1 INTRODUCTION

Every economic sector of the United States is dependent on a continued supply of high-Btu, pipeline quality gas to maintain present levels of activity. Almost a third of the total domestic energy consumption comes from gas, and strong incentives exist for maintaining that proportion as the overall demand for energy increases. However, the decline in new gas reserve additions and recent supply curtailments, especially notable during the 1976-1977 winter, clearly dramatizes the growing uncertainty as to whether current supply sources can adequately satisfy future demands for high-Btu gas.

The primary objective of this study is to provide decision makers of both government and the gas industry with a systematic base of information on the social costs likely to result from the development and implementation of technologically viable gas supply options from 1985-1990. The assessment is

limited to the analysis of four supply options and associated transmission pipelines. These are:

1. Increased offshore production of nonassociated gas,
2. Imported liquefied natural gas (LNG),
3. First-generation Lurgi gasification of domestic lignite, and
4. First-generation Lurgi gasification of domestic bituminous coal.

Because these technologies each supply gas which is essentially equivalent, the benefits to consumers per unit of output are largely independent of the technology selected. Yet, the costs to society, including those for labor, capital, and raw material, as well as the effects on such aspects as public health and occupational and nonoccupational safety, the natural environment, and national security, may very well differ for any one of the set of alternative systems.

Thus the scope of this assessment includes the identification and comparison of the social costs associated with providing an incremental supply of high-Btu, pipeline quality gas from each of the supply options in the 1985-1900 period. The scope is limited to the assessment of costs to supply gas to the Chicago-Northern Indiana area.

The assessment focuses on the physical effects and the technical and economic factors related to the costs of supplying high-Btu gas by alternative methods. Four general areas are emphasized:

1. Resource use and environmental residuals,
2. Conventional construction and operating costs,
3. Socioeconomic impacts of construction and operation, and
4. Human health and safety impacts.

A comprehensive literature search and information synthesis provides the basis of the assessment. Wherever possible the social costs are quantified. In some cases, however, as with the effects on human health and national security, the costs are not quantifiable. In these cases, the costs are presented only in a qualitative but comparative discussion of the alternatives.

The social costs that are quantifiable are identified and given within a reference system framework that characterizes each option. A net production

output of 250 million cubic feet per day (MMcfd)* serves as the basis for defining a reference system for each supply option, and quantifiable social costs allied with each system are assigned. This methodology provides a format for presenting the costs for each system on a normalized basis, which facilitates comparison. It also provides an indication of the absolute magnitude of impact associated with a single nominally sized incremental supply addition.

In the report sections that follow, the historical trends in gas reserves, production, and consumption are reviewed and a description of the assumed conditions for the 1985-1990 period is discussed briefly. After this preface, the assessment methodology is defined in detail, along with the concept of social cost and the level of assessment analysis to be used. Next, a series of sections is devoted to the definition of the alternative reference systems, transmission pipelines, and associated quantifiable costs.

In the final section, each category of social cost is displayed in its own table for easier comparison. These presentations are supplemented with a discussion of the social costs that are not quantifiable, leaving the reader with a structured and systematic data base.

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*Unit measures follow gas industry usage; MMcfd = million cubic feet per day; MMBtu = million Btu.

2 NATURAL GAS RESOURCES, PRODUCTION, AND USE

The information given here provides both historic and current perspectives regarding domestic and world natural gas resources, production, and use. These data also supply a means of framing the social cost assessment within an overall view of the natural gas industry.

Federal regulatory controls have had a strong impact on the industry. A discussion of these controls can be found in Appendix A. A more detailed and comprehensive presentation of historic and future trends in natural gas resources, production, and use is furnished in Appendix B.

2.1 NATURAL GAS RESOURCES

As of December 31, 1974, demonstrated reserves of domestic natural gas were estimated at 237.1 trillion cubic feet (tcf). During 1975 demonstrated reserves were altered downward by 8.9 tcf for a 1975 year-end reserve base of 228.2 tcf. Inferred reserves as of the end of 1974 were estimated at 201.6 and undiscovered economically recoverable resources at between 322 and 655 tcf.[1] Before 1967 demonstrated reserve additions kept pace with or exceeded net production. This trend reversed in 1968 with net production in excess of reserve additions for the first time in the history of domestic gas production. With the exception of 1970, the period of 1968 through 1975 has shown annual reserve additions at only about half the annual net production rate. Reserve additions exceeded production in 1970 largely as a result of the addition of 27 tcf of new field reserves discovered in Alaska's Prudhoe Bay area.

Demonstrated natural gas reserves steadily increased from a 1918 value of 15 tcf to 46 tcf in 1930 and 185 tcf in 1950. They increased in the 1950-1968 period at an average rate of 2.6% per year, reaching a peak of 293 tcf in 1968. Since 1968, proved reserves have shown a declining trend to the 1975 year-end reserve estimates of 228.2 tcf. The ratio of demonstrated recoverable reserves to net production has steadily declined from a value of 31.9 tcf in 1946 to 26.0 in 1950, 19.7 in 1960, 13.0 in 1970, and 11.3 in 1975.

In comparison to domestic demonstrated reserves of 228.2 tcf at the end of 1975 and 237.1 tcf at the end of 1974, the U.S. Bureau of Mines estimated worldwide demonstrated reserves at 2253 tcf as of December 31, 1974. This

value is a rough estimate because no international standards defining categories of natural gas reserves exist; it is almost a factor of 10 greater than the demonstrated reserves of the United States.

2.2 *NATURAL GAS PRODUCTION*

Marketed production of domestic natural gas has increased steadily between 1950 and 1973 at a compound annual rate of over 5.7% from 6.3 tcf in 1950 to 22.6 in 1973. It declined between 1973 and 1975 to 20.1 tcf or 11% below the peak 1973 production rate. About 4/5 of the gas is produced from gas-only wells (nonassociated) and the rest is a co-product with crude oil (associated).

The major producing region in the United States comprises Texas, Louisiana, Oklahoma, and Arkansas. This region produced 75% of all domestic natural gas in 1955, and 81% in 1975.

Natural gas production from the federal and state regulated offshore areas of Louisiana, Texas, Alaska, and California has increased from 1.4% of the nation's total in 1955 to 21.0% in 1975. Louisiana has had the largest share of offshore production, accounting for over 90% or 3.8 tcf of the 1975 offshore marketed production.

Offshore production from federal Outer Continental Shelf (OCS) waters accounts for over 80% of the total offshore production. This proportion has grown (with some minor setbacks) from a low of 47% in 1957. Cumulative production from the OCS through 1975 accounted for 75% of the total offshore production of natural gas.

Annual natural gas production in the United States is approximately half of the total estimated world production. That proportion has declined in recent years from 57.5 in 1970 to 41.7% in 1975. The downward trend is due primarily to a stabilization and slight decline in domestic production coupled with an increase in production in other parts of the world, notably Europe and Asia. The next largest producers are the U.S.S.R. and Canada, with 1975 marketed productions of 10.2 and 3.1 tcf, respectively.

2.3 *IMPORTS AND EXPORTS*

Imported and exported natural gas is now transported by two modes: overland pipeline and ocean tanker, the latter liquefied gas. A small amount of liquefied natural gas (LNG) also has been imported from Canada by tank truck for peak shaving applications in the North Atlantic states.

Pipeline gas trade with both Mexico and Canada began in the early 1950s. Until 1957, imports exceeded exports to Mexico. In 1958, pipeline exports were first exceeded by imports from Canada; and in that year the United States became a net importer of natural gas, a condition that has continued through 1975. Between 1958 and 1973, net pipeline imports grew at an average annual rate of 16%, reaching a peak of just over 1.0 tcf in 1973. Subsequent years have seen a decline in net pipeline imports as imports from Canada and Mexico decline more rapidly than exports to these countries.

In 1969 Phillips Petroleum Company and Marathon Oil Company began exporting liquefied natural gas from the Cook Inlet of Southern Alaska to Yokohama, Japan. Phillips and Marathon are now exporting the equivalent of about 50 billion cubic feet (bcf) of natural gas annually to Japan. The importation of significant amounts of LNG began in 1970 with the beginning of imports from Algeria by Distrigas Corporation at Everett, Massachusetts. These imports have increased from 0.8 bcf in 1970 to nearly 5.0 bcf in 1975.

2.4 *CURTAILMENTS*

The reporting of curtailments by interstate pipelines was not required until August of 1973. Interstate pipeline companies now are required to file such a report with the Federal Power Commission twice annually. Curtailments are defined for two types of service contracts, firm and interruptible. By a firm delivery contract, a pipeline company promises to deliver a fixed amount of gas over a specified time interval. A curtailment of these deliveries occurs when the amount the pipeline company is capable of delivering falls short of the contracted volume. Curtailments to interruptible customers, on the other hand, are based on reductions in normal deliveries to such customers (i.e., curtailments over and above normal curtailments of interruptible load).[2]

Annual firm contract curtailments have increased in trillions of cubic feet from just over 1.0 during the 1972/1973 reporting period to nearly 3.0 during the 1975/1976 period, and are projected at 3.8 for the 1976/1977 period.

Curtailments in interruptible sales between September 1975 and August 1976 totaled over 0.4 bcf or 68% of the interruptible sales requirement. Projected curtailments for the 1976/1977 reporting period are for nearly 72% of requirements.

It should be noted that these curtailments represent those made by 52 interstate natural gas pipeline companies to their customers. Because 90% of the natural gas sold by interstate companies is delivered to distributors who in turn provide gas to consumers, the curtailments are made largely at the wholesale level.

2.5 NATURAL GAS CONSUMPTION

Domestic natural gas consumption rose at an average annual rate of 6.8% between 1950 and 1972. After a peak consumption of 19.9 tcf in 1972, annual gas usage declined about 12% to a 1975 value of 17.5 tcf.

Relative quantities of natural gas consumed annually by the various economic sectors has remained fairly stable since 1950. Industrial gas consumption (including electric utility use) has accounted for approximately 60% of the annual gas usage. The residential sector has typically accounted for about 30% of the domestic gas consumption and the commercial sector and other miscellaneous users accounted for the remaining 10%.[3]

Gas utility customers have increased steadily since 1950 accumulating at an average of 2.5% per year between then and 1975. Consumption per customer has also increased steadily between 1950 and 1972 growing from an average in 1950 of 175 to 398 MMBtu/customer in 1972. Natural gas energy consumed per customer declined from 1973 through 1975 to 334 MMBtu/customer, a reflection of the decreasing industrial energy consumption that has exhibited a general declining trend since 1971.

2.6 FUTURE GAS SUPPLY AND CONSUMPTION

Natural gas reserves and resources are not estimated to be revised dramatically upward or downward within the near future. These estimates will

change between now and 1985, but this change is expected to evolve in a reasonably predictable manner, as approximated from industry and government projections.

The annual additions to reserves from gas exploration activities are not expected to change significantly in the near future; however, the number of active drilling rigs has increased in the last year. If this trend continues, larger reserve additions are likely. Annual proved reserve additions will probably be at a level between 8 and 16 tcf per year in the next decade. Any short term perturbations in this trend (as in 1970 with the introduction of Alaskan reserves) will not greatly affect the overall resource and reserve estimates.

Gas will be supplied primarily from onshore fields, but this source will continue to decline and more dependence will be placed on the Outer Continental Shelf reserves. By 1985, Alaskan gas may be flowing into the Midwest and east central regions via a Canadian-North Border pipeline system. Canadian and Mexican imports are expected to be nominal. Mexican imports have already declined to zero, but a pipeline to Texas from that country's recent large discoveries is being discussed. Canadian gas is expected to continue its general downward trend or to stabilize at some small value, probably less than 1.0 tcf per year. Very small amounts of gas may be supplied from geopressured reservoirs and the gasification of liquid hydrocarbons, but the former supply will not be significant before the mid-1990s.

Two supplemental gas supply technologies are deemed potential candidates for the supply of significant quantities of high-Btu gas by 1985; the importation of liquefied natural gas and coal gasification. The technology for LNG has been developed and is now being applied in the United States and in other parts of the world. Coal gasification is undergoing active research and development in the United States and has been successfully demonstrated in Europe for the production of low-Btu gas. Thus the technology for coal gasification is nearly in hand and neither it nor the importation of LNG is thought to be constrained because of technological reasons.

New gas customers are expected to be added, without much restriction, in the residential and commercial sectors in areas being serviced by major gas transmission and distribution systems. New industrial consumer additions are expected to be small and probably will not offset the conversion of present-

users to alternate fuel sources. The use of natural gas by electric utilities for baseload generation will continue to decline in the future as interstate gas is phased out as an allowable utility boiler fuel and as a result of producer states' energy policies. The demand for high-Btu gas in 1985 will likely be in reasonable balance with supply at between 18 and 22 tcf per year -- approximately the amount consumed in recent years.

2.7 FUTURE PRICES, POLICY, AND REGULATION

New gas prices are expected to continue to approach a value competitive with intrastate gas and imported oil, despite the fact that continued regulation of wellhead gas prices into the future is somewhat uncertain. Even if gas prices are deregulated, the legislation is expected to contain a predetermined escalation rate, thus maintaining in effect regulatory control over the transition period and prohibiting unusually large price increases over short time intervals.

Other expectations are that competitive bidding for federally controlled onshore and offshore lands will continue under the current federal leasing program. Offshore lease sales are projected at a rate of 5 or 6 per year similar to the proposed leasing schedule issued by the Bureau of Land Management in November 1976.[4] Whether this schedule is realized will depend on the availability of sufficient manpower and equipment to explore potential lease areas. Lacking sufficient exploration capabilities, future leasing would progress at a slower rate. The leasing rate and the bonus paid per acre are important parameters in the economics of natural gas production. The leasing rate will have an effect on the amount of gas dedicated to the interstate market, whereas the bonus paid per quantity of gas discovered and produced determines a major percentage of the price required to pay back the producer on his investment.

The above and many other factors create a broad spectrum of possible developments for the supply of natural gas in 1985, and it is not possible to predict the exact set of conditions that will exist then. Although the reader needs to be apprised of these possibilities, the assessment given here is not sensitive to their outcome. Rather, it should aid decision makers in formulating future policies and regulations. Possible future conditions have been presented reviewing a set of major options and circumstances that may exist by

1985. This information, like the historical data supplied, is provided as a means of framing this assessment within an overall view of the natural gas industry.

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3 ASSESSMENT METHODOLOGY

The scope of this assessment has been defined to include the identification and comparison of the social costs associated with alternative methods of providing an incremental supply of high-Btu gas to the Chicago-Northern Indiana Area in the 1985-1990 time frame. The assessment of social costs for alternative technologies requires a comprehensive and consistent framework, within which the assessment is conducted and through which its results are systematically presented. In the comparative assessment framework used in this study, the energy supply alternatives are evaluated in terms of reference energy systems, each supplying nearly equal quantities of the same form of energy at a specific location. With the primary benefits equalized, the social costs of the systems can then be compared.

Within this structure, the impacts can be identified, quantified where possible, and compared for the various energy systems. A consistent choice of assessment boundaries is defined so that the systems and impacts are indeed comparable. The quantifiable impacts for the energy systems under consideration are compared directly, and nonquantifiable impacts are discussed. Thus, no attempt is made to reach an arbitrarily defined overall "bottom line" score for the energy systems. Even a simple ranking from "better" to "worse" is not given, these evaluations requiring the imposition of social values to attach weightings to the disparate impacts involved. This work does, however, strive to categorize and summarize the impacts in a form that allows the decision maker to apply his own values in reaching a decision or at least to identify the major difficulties in each energy system.

In this section, we define the boundaries within which the alternative gas supply systems are analyzed and outline the concept of "social cost;" we also address the salient aspects of the comparative methodology and level of analysis.

3.1 ASSESSMENT BOUNDARIES

The alternative high-Btu gas supply systems chosen for assessment in this study include:

1. Increased offshore production of nonassociated gas,
2. Importation of liquefied natural gas (LNG),

3. First-generation Lurgi gasification of domestic lignite, and
4. First-generation Lurgi gasification of domestic bituminous coal.

Each of the alternatives is assessed under the assumption that it will provide an incremental supply of gas to the Chicago-Northern Indiana area beginning between 1985 and 1990.

These four systems constitute a very diversified set of alternatives with respect to their feed material, and thus their acceptable geographical locations necessary to provide gas to the demand area conveniently. Generalized siting areas were defined for each alternative based on the assumption that each would be located in a region that is capable of supplying its process feed and with consideration of existing gas transmission logistics. For example, the off-shore production and LNG importation alternatives are assumed to be located in the Gulf Coastal region of Louisiana, since a well-developed transmission pipeline network between that region and the demand area already exists. These supplies would not be expected to originate from the East Coast, because the major gas movements in the corridor between there and the Chicago-Northern Indiana Area are generally eastward. Although no transmission pipeline now exists between the Nation's largest lignite reserves in North Dakota and the demand area, the siting of a lignite gasification plant in the vicinity of these reserves would be expected to result in the transmission of the product gas to that area — perhaps via a newly constructed pipeline. Gasification of bituminous coal is assumed to take place in southern Illinois and, depending on the specific location of the gasification facility, this alternative may or may not utilize existing pipelines.

The discussion and comparative assessment of the social costs associated with a diversified set of technologies can be facilitated by defining the social impact interactants in terms of their relative positions within the social system. These interactants can be conceptualized as consisting of a nested sequence of three boundaries, each defining a separate level of participant interaction within the society.

The first level of interactants is defined by the process boundary. Within the process boundary are all activities directly associated with the supply of high-Btu gas for distribution and consumption in the demand area. As implied, these activities extend from initial exploration, through extraction and processing, to transmission for final distribution and consumption. Both the developmental and operational activities associated with each of these generalized process components are included.

Perceptible impacts external to the process boundary are defined to be bounded by the "perceptible impact boundary." In principle, the social costs resulting from environmental and socioeconomic perturbations caused by activities within the process boundary are shared by all members of society. In practical terms, however, many of the impacts resulting from a localized deviation from a preexisting norm may be only measurable or perceptible within some subset of that society. This boundary completely encloses the process boundary and is, itself, a subset of society.

The U.S. society forms the third boundary. In this study, society is defined in a nationalistic sense. It includes all of the United States, its populace, environment, and governmental and socioeconomic infrastructures. In geographical terms, this boundary includes the entire U.S. (including Alaska and Hawaii), and its adjacent offshore areas to a water depth of 200 meters -- the internationally approved limit of the outer continental shelf. For the purposes of this study social costs occurring outside the U.S. are not considered.

The activities within the process boundary require several process inputs: capital, labor, and nonfuel supplies. Process capital is represented by all plant and equipment directly utilized in exploration, production (importation), processing, and transmission of the gas supply. The labor services utilized include all direct work activities necessary for the construction and operation of the various stages in the process. Nonfuel supplies include all materials necessary to support direct process activities. These resources are viewed as entering the supply process from within the perceptible impact boundary. That is, the provision of these inputs impacts society in a more or less discernable manner.

Mineral fuel resources are also a major input to each of the high-Btu gas supply technologies. Mineral fuel resources include natural gas present

in reserves as well as other primary fuels for which a potential exists for conversion to high-Btu gas. Within the 1985-1990 time frame of this study, attention to "other primary fuels" is limited to domestic lignite and bituminous coal resources. Use of domestic mineral fuel resource inputs can be viewed as causing higher order impacts within the general society because the consumption of these nonrenewable resources denies their use to all future members of that society.

Outputs from the supply processes include the primary benefit, or the high-Btu product gas for distribution and sale to ultimate consumers, and secondary material benefits in the form of usable by-products. Other outputs include the costs to society for the privilege of exploiting the benefits provided by the supply system. The sum of these costs is termed "social cost."

3.2 SOCIAL COSTS

Social cost is intended to convey the concept of the total cost to society of an activity that provides a commodity or service to any or all societal segments. The infrastructure of social costs is made up of various classes of internal and external costs.

Internal costs are those monetary charges that compose the final sale price of the goods or services provided to society. Such charges include costs for capital expenditures for equipment, engineering and design, lease and property acquisitions, and wages. Since monetary costs are accounted for and passed along from all previous sellers to subsequent buyers, the final sale price of a commodity reflects the monetary value added to that commodity by all previous activities necessary in its production. For example, the final sale price of a cubic foot of gas reflects the wages of the foundry workers who processed the steel utilized in manufacturing the compressor ultimately sold to the gas producer for use in his gas production activities.

External costs, on the other hand, are costs not included in the sale price of the product but paid by both present and future members of society in various ways that may bear little relationship to their use of the product. Examples of external costs (or externalities) include property damage and personal injury not compensated for in monetary terms, damage to the natural environment, and aesthetic impacts resulting from the operations associated with providing a product or service. Some external costs are readily quantifiable in dollars or other physical units, but others are not.

External costs can be divided into three parts: primary, secondary, and higher order externalities. Primary external costs are those related to the construction, operation, and decommissioning of facilities utilized directly in producing a commodity. Thus, primary externalities emanate from activities within the process boundary. The secondary external costs are those that result from the supply of capital and operating goods from outside the process boundary. These costs, by way of parallel, mainly emanate from the sites and activities associated with the capital and operating goods industries that supply the main production process. These are difficult both to trace and quantify within the social system, and hence are not considered except for large or special secondary impacts.

An example of higher order costs are those to be paid by future societies, resulting from the use of nonrenewable resources by previous or present societies. Although the depletion of nonrenewable resources will likely take the form of higher internal and primary external costs in the future, it is the use of these resources today, and thus the denial of their use by future societies, that results in higher order costs.

External costs may be considered to be bounded by two extremes: costs that can be internalized and those that cannot. In general, some of the external costs of many activities may be converted to internal costs by changes in facility design and operation or by abatement techniques. In most cases, some external costs exist even after efforts are made to internalize them. Usually, however, society would not be operating at an optimum if it sought to achieve a complete internalization of costs. Indeed, a significant cost penalty may exist because the incremental internal costs required to eliminate some final external effect may be very large and not justifiable by the resultant increment of social benefit.

This assessment attempts to compare alternative high-Btu gas supply systems in the 1985-1990 period on the basis of both internal and external costs. Where possible these costs are quantified. In other cases, where costs assignable to an activity are not quantifiable, the comparison is made within a qualitative discussion. Due to the restrictions on time and effort available for this study, the assessment of external costs was limited to primary externalities. It is recognized that a complete assessment should include secondary and higher order external costs. The problems associated

with opportunity costs and future optimum use of high-Btu gas supplies are not addressed in this study. Indeed, the information provided by this assessment may well aid others in attacking such problems.

3.3 REFERENCE SYSTEMS FOR ENERGY-SUPPLY TECHNOLOGIES

This assessment utilizes a reference system approach, by which a nominal-sized system is defined for each of the 1985-1990 alternative high-Btu gas supply technologies. Quantifiable costs are determined and assigned to each of the reference systems and, since each system is defined with equal benefits to society, the comparison of quantifiable costs is simplified.

Non-quantifiable costs, such as the net impact associated with an increase in dependence on foreign energy supplies or the relative health impacts of the alternative systems, can also be addressed. These costs, however, may not necessarily be dependent on the definition of the reference systems, but in many cases may constitute generalized effects that require the decision-maker's consideration in the course of his evaluation. Thus, the reference system approach is merely a technique for normalizing quantifiable impacts and presenting them at an associated level of magnitude that is representative of feasible incremental supply additions.

A single criterion dominates the reference system definitions: The definition of each reference system must reflect those system characteristics that are expected to be typical of the general technology during the time period being considered in the assessment. Obviously, as technologies are projected further into the future, typical technological conditions become more difficult to identify and may be accomplished only at a lower level of confidence.

A net production output of 250 million cubic feet per day (MMcfd) serves as the basis for defining the alternative gas supply reference systems. The design of each system is based on a comprehensive analysis and technology characterization of existing, planned, or conceptualized systems for the 1985-1990 period. Due to the near-term nature of the study, the majority of each technology characterization and reference system definition was synthesized from information available in the current literature. Most facilities existing in 1985 are not expected to be substantially different from those now under

consideration. Thus, with one exception, the reference system definitions are based on detailed engineering designs and analyses. The exception is Lurgi gasification of Illinois bituminous coals. Although facilities of this nature are being considered by the gas industry, engineering designs were not yet available to us, so that we had to make extrapolations from current western subbituminous and lignite coal gasification designs based on the results of gasification tests on various U.S. coals in a Lurgi gasifier at Westfield, Scotland.

Strictly speaking, the net benefit derived by society under the assumed conditions is the production of 250 MMcfd of high-Btu gas, less transmission losses and pipeline fuel usage for transporting that supply from its point of origin to the assumed demand area. Because the alternative technologies would be located at different distances from the Chicago-Northern Indiana demand area, that net social benefit would be expected to differ for each system. The approach taken here is to view the transmission segment associated with each technology as an add-on system with its own discrete social costs. This more generalized approach enables the decision maker to evaluate each supply option separately, on its own terms, as well as to consider the impacts of transmission.

3.4 CATEGORIZATION OF IMPACTS

As stated previously, the scope of the study has limited the concepts of social costs to the internal and primary external costs of the systems being compared. The following categories of impacts are considered:

1. Conventional dollar costs (internal costs)

    a. Capital costs
    b. Operating costs

2. Resource use

    a. Minerals
    b. Land
    c. Air
    d. Water
    e. Manpower (labor)
    f. Capital Resources

3. Environmental consequences

a. Effluents and other physical impacts
b. Alteration of ambient conditions of air, water, and land
c. Effects on natural systems
d. Effects on property and economic activities

4. Human health and safety

a. Effects on the general public

(1) Effluent-induced morbidity and mortality
(2) Accidents

b. Occupational health effects

(1) Exposure to effluents
(2) Accidents

5. Socioeconomic consequences

a. Employment for construction and operation
b. Induced secondary employment
c. Demographic change
d. Impact on local housing and public services
e. Fiscal and administrative impacts
f. Sociocultural change

3.4.1 Conventional Dollar Costs

Internal costs are exhibited as conventional dollar costs associated with the construction and operation of the gas supply alternatives. The assessment presents these costs to provide reference points for the comparison of external costs and to illustrate the relative economic competitiveness between the alternatives. All dollar costs are given in 1975 constant dollars and are based on 1975 cost levels. Future changes in these cost levels are not projected; however, additional costs that may result due to expected changes in certain physical conditions between now and 1985 are included. For example, future gas reserves found in the Gulf of Mexico are expected to be somewhat smaller than those already located. Thus the amount of effort and capital required to tap them is expected to be somewhat greater than has prevailed historically.

3.4.2 Resource Use

Although resource inputs are included in conventional dollar costs, they should also be examined as physical quantities with finite availability. Mineral resource use consists primarily of direct feed material utilized in

supplying gas for transmission and ultimate consumption. Where information was available, data on material for supplementary processes is included. No attempt has been made to assess the resource requirements necessary to support activities outside the direct process activities within the process boundary. Land and water requirements are assessed for each of the alternative technologies. Land requirements are addressed in three forms: acre-years required during construction or development, acres necessary to support the direct supply activities over an assumed economic lifetime, and acres per year disrupted to support supply activities. The use of littoral and offshore regions has also been included as land use for this assessment. Water requirements in the context of this study refer to consumptive uses of this resource. Direct manpower requirements are assessed for both the construction and operational phases of each of the alternatives. Capital resources refer to the investment required in comparison with the economic resources of the entities financing the system.

3.4.3 Environmental Consequences

Residuals of the construction and operation of the energy systems affect air, water, and land. The majority of residuals can be quantified in physical units of residuals produced per unit of high-Btu gas produced by the reference energy supply systems. The air effluents include such constituents as sulfur oxides, nitrogen oxides, hydrocarbons, carbon monoxide, and particulates. Water effluents may be characterized as dissolved and suspended solids, biological oxygen demand, and other factors. Land is required to dispose of solid wastes, expressed in tons and volume of material, which may subsequently contribute to air or water pollution. If local conditions are known, ambient concentrations of air and water pollutants can be calculated. Finally, effects on natural systems and consequences to property and economic activities can be assessed. In this work, however, considerations are limited to effluents produced by the reference systems.

3.4.4 Human Health and Safety

Health effects result from the emission of residuals that are inhaled by humans or enter the human food chain. The quantitative relationships of human health with residuals, however, are largely unknown. For ethical reasons,

it is not usually possible to study in man substances suspected of leading to lethal outcomes. As a consequence, the results of animal experimentation, with its associated problems of interspecies variation, are often a major source of data, although not directly applicable to humans.

With the absence of quantitative dose-response relationships for human exposure to environmental stresses or noxious agents, the treatment of health effects in this study takes the form of a general discussion of their nature. Some discussion is also presented on the uncertainties surrounding the deposition and ultimate fate of trace elements, particularly as a result of the coal gasification processes and offshore drilling operations.

Finally, occupational and nonoccupational safety issues are addressed. Where statistical data was available, an estimate was made of the annual man-days lost by both occupational personnel and the general public as a direct result of the supply system's operation. Fatalities and disabling injuries are listed separately. No attempt has been made to quantify the dollar costs associated with these accidents.

3.4.5 Socioeconomic Consequences

Regional socioeconomic impacts can be estimated on the basis of direct employment requirements. Since most workers are adverse to commuting more than 60 minutes one way to their employment site, the socioeconomic impacts are limited mainly to areas surrounding the supply development site that meet this condition. A socioeconomic impact assessment methodology developed at Argonne National Laboratory was utilized to investigate these impacts. It is site specific in nature, so the approach taken was to subject representative sites to analysis and then to infer the impacts expected to prevail in the general areas where each of the alternatives might be sited. The assessment of socioeconomic impacts is restricted to direct, indirect, and income-induced employment in the general vicinity of the development site. Impacts associated with nonlocal support industries have not been included. A complete analysis would include an assessment of impacts on housing and public services and consequent effects on governmental finance and administration. Neither these impacts nor sociocultural changes are discussed here.

3.5 LEVEL OF ANALYSIS

This study analyzes the most salient impacts of the alternative gas supply systems. The conventional dollar costs, both capital and operating, are estimated. Resource use is quantified and tabulated for the alternatives, as are the major environmental residuals. Occupational health and safety impacts, measured in fatalities, injuries, and man-days lost, also are estimated. Although the socioeconomic impacts are not quantified, employment data are shown, and a typical curve of population growth with time is calculated for one case. Public health and safety are discussed qualitatively.

Results of the comparative assessment are shown by tabulating values of impacts for the four alternative gas supply systems. Components of the social cost that can be quantified are presented in their appropriate physical units, with no attempt made to reduce all impacts to a common metric such as dollars. In this way only comparable impacts are actually compared, and no overall evaluative scoring or ranking of alternatives is made. Nonquantifiable impacts are merely identified and discussed.

4 OFFSHORE PRODUCTION OF NATURAL GAS IN THE GULF OF MEXICO

As future production of natural gas from existing onshore reservoirs declines, much of the deficient supply is expected to be obtained from the production of gas from resources underlying the Outer Continental Shelf (OCS). The leading OCS production area is in the Gulf of Mexico, principally off the coast of Louisiana. Although the U.S. Department of the Interior plans to hold several OCS lease sales per year covering portions of nearly all potential offshore petroleum areas, the Gulf of Mexico is expected to dominate offshore gas production over the next decade.

A highly developed oil and gas industry exists along the coastal areas of Louisiana and Texas, and a massive pipeline transmission system extends through a corridor north to the Great Lakes states, and northeast to the Ohio, Pennsylvania, and New York regions. The Great Lakes states of Illinois, Indiana, Michigan, and Wisconsin now receive over 25% of their interstate gas from the offshore Louisiana area, and over 54% from the general area that includes onshore southern Louisiana and the onshore and offshore areas of the Texas Gulf Coast.[1]

This section defines a nominal 250 MMcfd reference production system in the Gulf of Mexico off the Louisiana coast. The reference system and its associated environmental residuals and costs are defined in terms of typical conditions (or designs) being implemented or planned in Gulf of Mexico OCS waters.

4.1 BACKGROUND AND CURRENT STATUS

The earliest offshore production of hydrocarbons in the United States was off the California coast in 1896 and resulted as a natural extension of previous onshore discoveries. These first offshore wells were drilled to a depth of about 600 ft from wooden piers extending from the shoreline.

In 1938, the discovery of the Creole field in the Gulf of Mexico, 1.5 miles from shore in 26 ft of water, marked the petroleum industry's first successful venture into open and unprotected waters. In November, 1947, a discovery was made in the Ship Shoal area of the Gulf, 12 miles from the Louisiana coast in 16 ft of water. Wells drilled in this area were the first to be drilled out of sight of land and the first to be drilled from a mobile

platform, beginning a technology that has been used to drill more than 18,000 offshore oil and gas wells in U.S. waters.[2]

Since the first federal sale of leases of OCS oil and gas in October, 1954, a total of 41 such sales have taken place -- thirty-three were for the Gulf of Mexico, four off the coast of California, one off the mid-Atlantic states, and one each off the coasts of Alaska, Oregon and Washington. OCS lease sales resulted in the leasing of 13,727,316 acres of public areas, of which just less than 70% remains actively leased. Table 4.1 summarizes OCS leasing through 1975.

Table 4.1. Summary of OCS Leasing Activity 1954 through 1976

	Offered		Leased		Active	
Area/Total	Tracts	Acreage	Tracts	Acreage	Tracts	Acreage
Gulf of Mexico	5351	24,779,906	2434	11,219,770	1708	7,868,091
California	471	2,470,570	185	988,170	124	656,857
Oregon, Washington	196	1,090,074	101	580,853	-	-
Mid-Atlantic	154	876,750	93	529,466	93	529,466
Alaska	189	1,088,499	76	409,057	76	409,057
Total	6361	30,305,799	2889	13,727,316	2001	9,463,471

Sources:
(1) Federal Energy Administration, *Project Independence Blueprint-Final Task Force Report, Natural Gas*, p. V-12
(2) Readinger, T.A., Bureau of Land Management, Div. of Marine Minerals, personal communications (1977)
(3) Piper, S.K., U.S. Geological Survey, New Orleans, La., personal communications (1976)

Table 4.2. Natural Gas Production: Gulf of Mexico OCS and Total U.S. (trillion cubic feet)

Year	U.S.	Louisiana	Texas	Gulf	Gulf as a % of U.S.
1965	16.0	0.64	-	0.64	4.00
1966	17.2	0.96	0.04	1.00	5.81
1967	18.1	1.09	0.10	1.19	6.57
1968	19.3	1.41	0.11	1.52	7.87
1969	20.7	1.82	0.13	1.95	9.42
1970	22.0	2.27	0.13	2.40	10.91
1971	22.4	2.63	0.13	2.76	12.49
1972	22.5	2.88	0.15	3.03	13.47
1973	22.6	3.06	0.15	3.21	14.20
1974	21.6	3.35	0.16	3.51	16.48
1975	20.1	3.32	0.12	3.44	17.11

Source: U.S. Geological Survey, *Outer Continental Shelf* [illegible] pp. 90-91 (June 1976)

Marketed production of natural gas extracted from the Gulf of Mexico OCS has increased at an average rate of 18.3% per year over the last decade. In 1965, gas marketed from the Gulf OCS comprised 4% of the United States total marketed production; by 1975 this source made up over 17% of the total. Table 4.2 compares these data on an annual basis for 1965 through 1975. Gas produced from the Federal OCS accounts for about 80% of all offshore gas produced in the United States. The remainder is produced from state-controlled offshore lands.[3]

Table 4.3 shows estimates by the U.S. Geological Survey of natural-gas reserves in U.S. offshore waters (0-200 meters of water depth), according to region. This data indicates that over 32 trillion cubic feet (tcf) of natural gas had been produced in the Gulf of Mexico offshore region as of the end of 1974. At that time, demonstrated reserves totaled nearly 36 tcf, with inferred reserves of 67 tcf. Undiscovered recoverable reserves were estimated by the USGS at 18-91 tcf, corresponding to respective probabilities of 95 and 5% of that amount of gas being in place.

4.2 OVERVIEW OF THE GAS RECOVERY TECHNOLOGY

Recovery of offshore gas reserves requires six activities: geological and geophysical exploration; sale of offshore leases; exploratory drilling; development drilling and well completion; production and workover; and final abandonment or well kill.

4.2.1 Surveys and Lease Sales

Surveys. Preliminary exploration is made to locate geologic formations that are potential oil or gas reserves. This is the first step in developing the Outer Continental Shelf. Geological and geophysical exploration usually takes place in two phases: regional surveys, to identify potential oil or gas bearing formation; and detailed surveys, upon which evaluation of specific lease tracts is based.

Areas found to be promising in the regional surveys are investigated in more detail. Seismic surveying is the most popular technique. With this technique, a source generates shock waves that travel through the water and penetrate the stratified ocean floor. Because of differences in density and thickness of these layers, the sound waves are differentially reflected and

Table 4.3. Production, Reserves, and Undiscovered Recoverable Offshore (Depths of 0-200 Meters) Gas Resources for the United States, December 31, 1974 (trillion cubic feet)

Region	Cumulative Production	Demonstrated Reserves (Measured)	Total Cumulative Production + Demonstrated Reserves[c]	Inferred Reserves	Undiscovered Recoverable Resources[b] Statistical Mean	Undiscovered Recoverable Resources[b] Est. Range (95%-5%)
Alaska	0.423	0.145	0.568	0.1	44	8-80
Pacific Coastal States	1.415	0.463	1.878	0.4	3	2- 6
Gulf of Mexico	32.138	35.348	67.486	67.0	50	18-91
Atlantic Coastal States	0.000	0.000	0.000	0.0	10	5-14
Total Lower 48 Offshore	33.553	35.811	69.364	67.4	63	26-111
Total Offshore United States	33.976	35.956	69.932	67.5	107	42-181

[a]Derived for all regions from historical data for national onshore average.

[b]The low value of the range is the quantity associated with a 95% probability (19 in 20 chance) that there is at least this amount. The high value is the quantity with a 5% probability (1 in 20 chance) that there is at least this amount. Totals for the low and high values are not obtained by arithmetic summation; they are derived by statistical methods.

[c]Estimates reported at the 75 and 25% probability levels because, in this area, these levels are judged to be more applicable for some planning purposes. In frontier areas, lacking discovered indigenous or adjacent recoverable hydrocarbons, uncertainty is great enough to weaken probability estimates at extreme ranges. For comparison with other recorded ranges, the 95-5% probability range in offshore Atlantic is 0-22 trillion cubic feet of gas.

Source: U.S. Geological Survey, *Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States*, Circ. 725, pp. 30-31 (1975).

refracted. The resulting echoes are picked up by underwater receivers trailing behind the research vessel, recorded, and later analyzed.

Lease Sales. A proposed lease sale usually begins with a call for nominations and comments by the Department of the Interior (DOI), followed by an invitation to industry to designate specific tracts it is interested in bidding on if a sale is held and to government agencies, private organizations and individuals to indicate areas they believe should not be leased. The call for nominations may, however, be neglected when the proposed sale is for drainage or development tracts, in which case the lease sale may begin with the issuance of a tract selection announcement by the DOI.

Once nominations are submitted, the initial tract selection responsibility lies with the Bureau of Land Management (BLM) and the U.S. Geological Survey (USGS). These agencies also consider recommendations by the U.S. Fish and Wildlife Service, conflicts such as defense warning zones, policy guidelines, and possible drainage of reserves from state lands. Nomination and tract selection, if routine, will generally take about one year.[4] Figure 4.1 shows procedures for federal OCS lease sales.

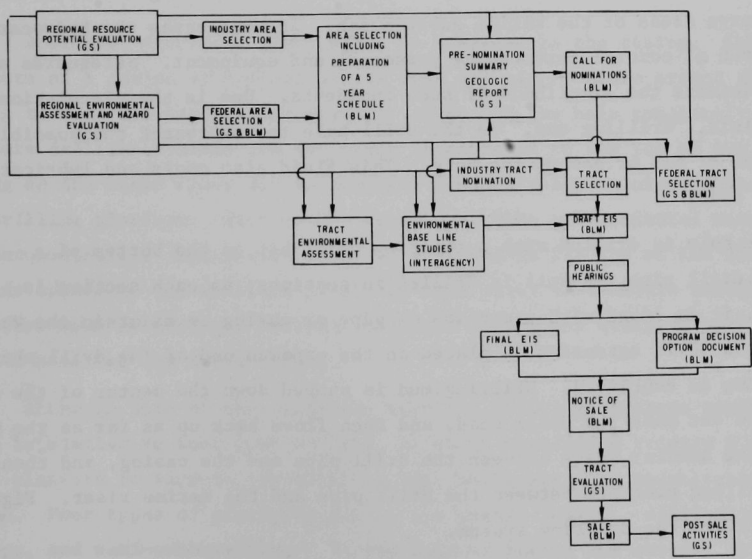

Fig. 4.1. OCS Leasing Procedures

4.2.2 *Exploratory Drilling*

Exploratory drilling is not permitted until after a tract has been purchased in a lease sale. Although additional seismic work may be carried out before tract development, exploratory wells must be drilled to determine whether commercial accumulations of oil or gas underlie the tract.

Exploratory drilling may also be conducted to extend known limits of previously discovered reservoirs. Exploratory well classifications used by the American Association of Petroleum Geologists (AAPG) and the American Petroleum Institute (API) include new-field wildcat, new-pool wildcat, deeper-pool test, shallower-pool test, and outpost or extension test. The degree of risk (probability of not finding hydrocarbons) is highest for the new-field wildcat and decreases to the outpost or extension classification.[5]

Exploratory drilling is one of the most hazardous phases of offshore development because of the possibility of a blowout -- a sudden surge of oil or gas pressure up the drill hole causing a loss of control over the well. Although in most blowouts only gas is released, large volumes of oil may also be released from associated reserves. The loss of oil during a blowout can pollute large areas of the marine environment. In some cases the hydrocarbons may burn out of control threatening personnel and equipment. Safeguards are used to minimize the likelihood of such incidents. One is the circulation of a heavy fluid, "drilling mud," in the drill hole to counteract the possible sudden flow of oil or gas up the hole. This fluid also cools and lubricates the drill head.

The hole is drilled with a rotating drill bit on the bottom of a string of drill pipe. A well is drilled in sections; as each section is completed, it is lined with a section of pipe or casing to maintain the wall integrity, a 30-ft extension is placed on the exposed end of the drill shaft, and drilling is continued. Drilling mud is pumped down the center of the drill pipe; flows out past the drill head; and then flows back up as far as the OCS floor in the annular space between the drill pipe and the casing, and then up to the drilling platform between the drill pipe and the marine riser. Figure 4.2 illustrates the drilling system.

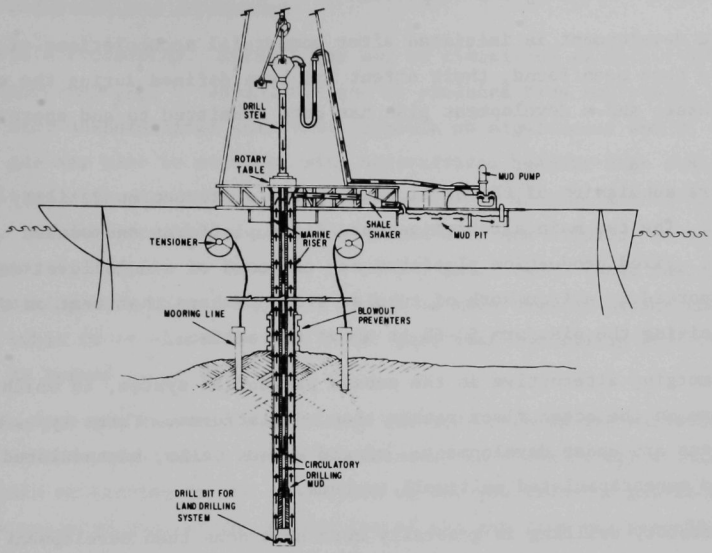

Fig. 4.2. Offshore Drill Ship

A blowout preventer (BOP) stack is attached to the casing. This device consists of a series of control valves that can either close around the drill string to seal off the annular space or close off the hole completely. On offshore drilling systems the BOP stack is attached to the top of the surface casing on the ocean floor and is operated hydraulically or electronically from the drilling platform. With either operation, BOPs are activated manually, not automatically. The marine riser is attached to the top of the BOP and extends upward to the drilling platform. The riser is flexible enough to allow for some lateral and vertical movement during the drilling operation without breaking the drill string.

Although much of the equipment used for drilling offshore exploratory wells is similar to that used on land, offshore operations require a water based platform to support the drilling rig, machinery, and mud-cleaning system. Four types of platforms are in use today: barges, drill ships, jackups, and semi-submersibles. In the Gulf of Mexico OCS waters, drill ships are used almost exclusively for exploratory drilling, while jackups are used for development drilling.

4.2.3 Development Drilling and Completion

Field development is initiated after commercial accumulations of hydrocarbons have been found, their extent has been defined during the exploratory phase, and a development plan has been submitted to and approved by the USGS.

Before submission of the development plan, a production facility must be selected. The two main alternatives are fixed platforms and seabed completions. Fixed production platforms are composed of a multilevel deck section supported by a framework of tubular steel members that rest on the sea floor raising the platform 50-60 ft above the surface.

An emerging alternative is the subsea production system, in which the wellheads are on the ocean floor rather than on platforms. Three types of subsea systems are under development: single subsea wells, encapsulated systems, and nonencapsulated multiwell systems.[6]

Exploratory drilling is generally more hazardous than development drilling because at that time the characteristics of the geologic formation are not as yet known.

When the desired hydrocarbon reservoir is reached the well is completed. Well completion encompasses a variety of activities required to allow safe and effective production from a drilled well and to minimize the need to reenter the well at a later date.

Completion generally includes setting and cementing casings and perforating them at specified depths to permit oil or gas to flow from the formation into the well hole while blocking the entry of liquids from nonhydrocarbon bearing strata. Perforation of the casing to extract oil or gas from more than one hydrocarbon zone simultaneously is known as a multiple completion.

Other completion activities include setting tubing for routing the hydrocarbons to the surface and installing downhole safety devices to prevent blowouts during production. Fracturing or acidizing may also be done at this time to increase the permeability of the formation. Although fracturing and acidizing are aimed at increasing production rates, they are not considered as servicing or workover operations if done during initial completion.[7]

4.2.4 *Production and Processing*

Field Processing. Natural gas may be classified as either *associated* or *nonassociated* gas. Associated gas is produced from reservoirs that also contain oil; nonassociated reservoirs contain no significant amount of oil. Natural gas may also be produced with hydrocarbons heavier than ethane (gas liquids) and with other *acid gases*, such as carbon dioxide and hydrogen sulfide. If the natural gas contains extractable gas liquids, it is classified as wet gas; if not, it is referred to as dry gas. Under Texas law, for example, gas containing more than 1.5 grains of H_2S or more than 30 grains total sulfur per 100 cubic ft is classified as "sour" gas; that containing less than these amounts is termed *sweet* gas.[8]

In most gas recovery operations, the hydrocarbons are extracted with varying amounts of brine or formation waters. In offshore operations, the usual field processing is the separation of the gas from the gas-water stream for nonassociated gas, or the separation of the gas from the gas-oil-water stream for associated gas. The formation water is discharged overboard or reinjected and the usable hydrocarbons are transported to shore for further processing.

Gathering and Transportation. A system of pipelines is used to collect and transport offshore gas to the shore. These pipelines serve to gather products from different producing platforms and route them to a central point for treatment and field processing before they are transported to shore.

Three techniques are used to lay offshore pipelines. The most common is the lay barge or *stovepipe* technique, in which sections of the pipe, usually coated with concrete, are welded together on a *lay barge* and released into the water as the barge moves forward. A second technique is the reel barge, in which long sections of pipe are welded together on land, wound onto a large reel on the barge, and then laid directly from the reel. The third method is to pull the pipe from the make-up facilities onshore into the water.

Although laying pipe directly on the undersea surface was formerly common, burying the pipeline to avoid damage from currents, storm waves, and anchors is now prevalent. A burial barge is used to sink the pipe beneath the surface, usually by displacing the subsurface soil with a high-pressure water jet.

Processing. Once natural gas and gas liquids (condensates) have been recovered, separated from formation waters, gathered, and transported to shore, the stream is processed through a processing plant to separate condensible liquids and hydrogen sulfide, and to produce a dry natural gas for sale. A typical sales specification for natural gas is a gross heating value of not less than 1000 Btu/cf; a maximum of 0.25 grains of H_2S per 100 cubic feet (cf), with a maximum of 20 grains total sulfur per 100 cf; and a water content low enough so that line freezeups will not occur.[9]

Several processes for treating the acid gas are commonly used in the United States. All produce a salable natural gas with respect to the acid gas content.[10]

Gas is usually further dehydrated on shore by glycol injection or with a solid desiccant. Gas liquids are separated from the stream by one of several processes. Separation processes now in use in the United States, include: absorption, refrigerated absorption, refrigeration, compression, fractionation, cryogenic separation, and turbo expansion.

Workover and Abandonment. Near the end of the life of a field, several techniques ("workover operations") may be used to increase the production of wells that have declined to noneconomical rates of production because of loss of formation pressure or other reasons. They may include fracturing, "acidizing," or even relocating the casing perforations in an attempt to produce more gas from the same well.

Fracturing may be accomplished by pumping a fluid down the well at high pressure to fracture the reservoir and increase its permeability. The increased permeability may significantly increase well production rate; explosives may also be used in fracturing.

In acidizing, permeability and production rates are increased by adding an acid to enlarge the openings in the formation.

When a well no longer can produce economical quantities of hydrocarbons, it is plugged and abandoned. Plugging and abandonment procedures are regulated by the USGS, which requires that cement retainers be placed in the well to a specified depth below the sea floor. In multiple completion wells, the operator must plug and isolate each perforation by a 200-ft cement plug extending 100 ft in either direction of the perforated zone. The USG also specifies

the pressure-testing procedure and criteria to be used on the inserted plugs before abandonment.[11]

4.3 *REFERENCE SYSTEM*

This section describes a typical 250 MMcfd net production offshore gas supply system. Characteristics of this reference system are summarized in Table 4.7.

4.3.1 *Location*

Gas recovery is assumed to be from federal OCS waters at 90 miles off the central coast of Louisiana and at a water depth of about 250 ft. This location is assumed to be near enough to existing gas-producing areas in the Gulf to allow a relatively easy connection of underwater gathering and transmission lines to the existing pipeline network. The recovered gas is gathered and transported to shore for final processing to separate natural gas liquids before being sold on the interstate market.

4.3.2 *Capacity and Operating Factors*

Based on information derived from mass balances constructed from U.S. Bureau of Mines data,[12,13] 285.3 million cubic feet per day (MMcfd)* of gross wet-gas well withdrawals is assumed to be required to provide a 250 MMcfd supply to pipelines after losses and process consumption. Of the volume withdrawn from the wells in MMcfd units 0.39 is vented, flared, or otherwise lost at the lease property; 11.70 is consumed as fuel at the production site and in the gathering and offshore transmission operations. A total of 273.21 arrives ashore at the processing plant, where 13.43 is extracted as liquids, 8.16 is consumed as plant fuel, and 1.62 is vented, flared, lost, or unaccounted for. The saleable outflow from the processing plant is thus 250 MMcfd. The process flow diagram for this system is presented in Fig. 4.3. It has also been assumed that wet gas withdrawn at the lease site, used as lease fuel, vented, flared, or unaccounted for has an average heating value of 1085 Btu per cubic

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*Note: Unit measures follow gas industry usage;
MMcfd = million cubic feet per day
MMBtu = million British thermal units

foot (Btu/cf). The component of that gas that is condensed and extracted as liquids has a heating value of 2258 Btu/cf, resulting in a gas with 1024 Btu/cf delivered to the transmission pipeline and used as process plant fuel.

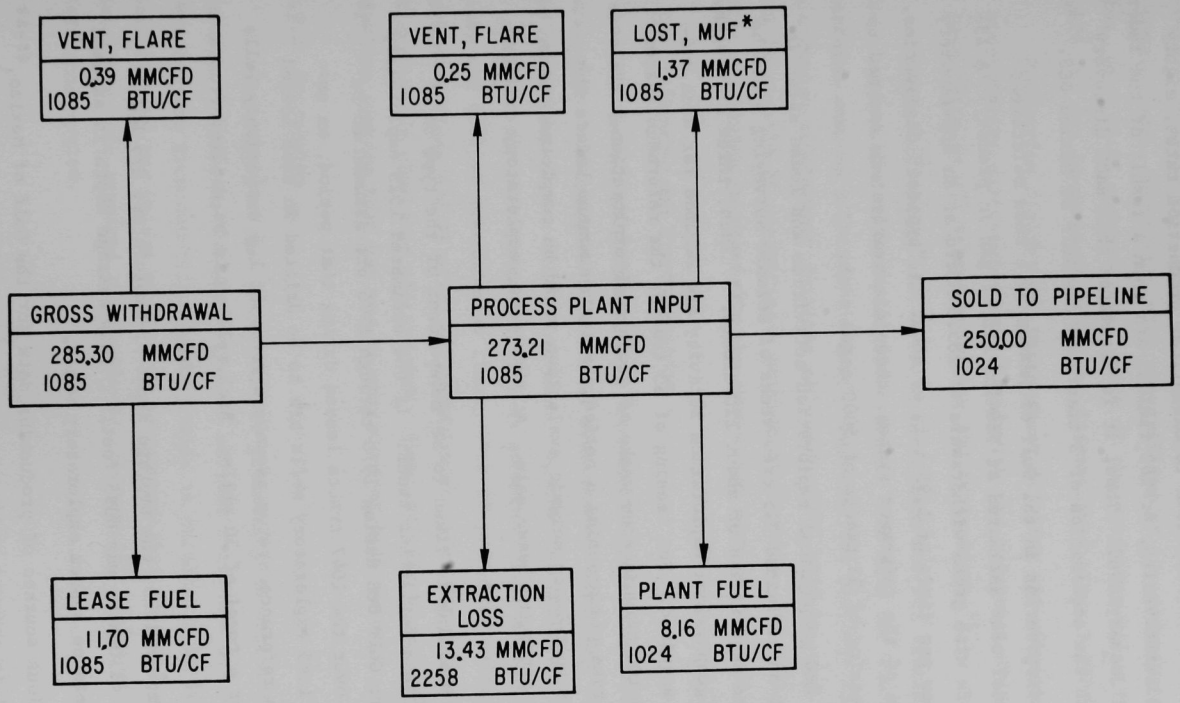
Because most domestically produced gas is nonassociated, as are nearly 90% of the offshore Gulf reserves, the reference system is assumed to produce gas from nonassociated reservoirs. The differences that would result by considering a typical mix of associated and nonassociated extraction are insignificant, and for simplicity the unmixed extraction is considered. Gas recovered from the offshore Gulf region is almost totally sweet gas. Typical of offshore Gulf of Mexico gas is an H_2S concentration of about 0.1 grain per hundred cubic feet. This value and 0.2 grains total sulfur per 100 cf are assumed for the reference system.

If net conversion efficiency is defined as the ratio of the energy content of the product and by-product to that of the gross withdrawal, this system would have a net conversion efficiency of 71.66%.

Gas-processing plants in 1975 had an average operating factor of about 67.7%. This factor, however, is partially determined by the amount of *gas* available for processing and not totally by the *plant's* availability for gas processing. The average capacity factor of the reference system processing plant is assumed to be 73% -- about equal to the capacity factor for Louisiana processing plants during 1975.[14] To process 273.21 MMcfd of gas and supply 250 MMcfd of dry gas to transmission pipelines, a process plant capacity of about 374 MMcfd is required. This capacity is only 1.65% of total Louisiana gas processing capacity in 1975; hence it is assumed that no new processing capacity is required; and that the incremental supply provided by the reference system replaces older declining supplies.[15]

4.3.3 Exploration and Production

Analysis of previous OCS lease sales and FEA projections indicate that a reasonable offshore lease acquisition cost is $2500 per acre and that Gulf of Mexico properties may be acquired in tract sizes of about 5000 acres each.[16] As of January, 1969, a total of 842 tracts had been acquired in general lease sales of federal properties off the Louisiana coast. These acquisitions and those in state controlled waters resulted in the discovery of 222 gas fields



*MUF = MATERIALS UNACCOUNTED FOR

Fig. 4.3. 250-MMcfd Offshore Production Reference System

and 131 oil fields.[17] If it is assumed that the oil and gas field discoveries in federal waters are in proportion to historical production rates, eighty percent of the 353 discoveries, or 282 fields, are then a result of the federal lease sales as of January 1969. Thus, it is estimated that each discovery is associated with the acquisition of 3 tracts on the Gulf of Mexico OCS.

Gas field discoveries in the Gulf of Mexico have been relatively small with a typical size estimated at 180-185 bcf of gas in place.[18] A 15-year operating life with gross withdrawals of 285.3 MMcfd at an 80%-recovery factor requires new gas finds of 1.95 tcf, or about 11 "typical" discoveries. For the definition of the reference system, these discoveries are assumed to result from the leasing of 33 tracts of 5000 acres each.

Geological and geophysical exploration activities and lease sales in 1973 indicate that an estimated 345 crew-weeks of seismic surveying would be associated with the acquisition of about 120 tracts.[19] Thus, three crew-weeks of geological and geophysical exploration activity are assumed for each off-shore lease tract acquired. For leasing of 33 tracts, the reference system assumes a total of 100 seismic crew-weeks of geological exploration. Prelease exploration would take place during a period about nine months before the lease sale, and the post-lease seismic evaluation would be completed within about three months after the lease sale. At this time, exploratory drilling would commence.[20]

Exploratory drilling is taken to be independent of the type of reservoir expected in a particular tract. If the estimated 1523 exploratory wells drilled on the Gulf OCS during 1970 through 1975 are assumed to be evenly distributed over the 1047 tracts leased during that period, an estimated average of 1.45 exploratory wells are to be drilled in each leased tract.[21,22,23] The reference system assumes a ratio of 1.5 exploratory wells per leased tract, or a total of 50 wells. Each well would be drilled from a mobile drill ship.

From 1970 through 1975, the average depth of exploratory dry holes drilled in the Gulf of Mexico was 8395 feet.[24] This average depth is assumed for each of the reference system exploratory wells.

Based on various sources of production data for the Gulf of Mexico,[25-28] each production well is assumed to produce at an average rate of 6.1 MMcfd, thus

the reference system requires a total of 47 producing wells. These wells are to have an average of 1.35 completions (perforation zones) each, for a total of 64 completions. Associated with the drilling of 47 producing wells are 19 dry holes, or a 71.2% success rate. Each of the producing wells is drilled to 10,620 ft; dry development holes are discontinued after 9,900 ft.[29]

Production Platforms. Development drilling and subsequent production of offshore gas discoveries associated with the reference system are assumed to take place in OCS waters averaging 250 ft in depth.[30]

These activities will be from three main and six satellite fixed platforms launched at the production sites. One main and two satellite platforms compose a production unit. Jackups, the platform type most common in offshore development drilling and production, will be used. Each unit will be capable of supporting a maximum of 22 wells, and will contain facilities and living quarters for the production crew on the main platform.

4.3.4 Gathering and Transportation

The length of gathering and transmission lines required for a particular development site may vary considerably depending on its location and characteristics. For the reference system, installation of 0.66 miles of pipeline for each producing well is assumed: 0.22 miles of gathering lines and 0.44 of transmission lines. For 47 producing wells, 10 miles of gathering lines and 21 miles of transmission lines for a total of 31 miles of underwater pipelines are assumed. Some use will be made of existing pipeline systems that may not be operating at full capacity.[31,32]

4.3.5 Processing

The supply of gas available for processing is decreasing faster than capacity to process the gas. Because of this condition and an indication that new gas from domestic onshore fields is tending to be leaner, yielding less liquids per volume of gas, it is assumed that no new gas processing facilities are required to process the incremental gas supplied from the reference system.

The amount of gas liquids extracted is assumed to be 25/bbl/MMcf of gas processed. This value is consistent with the historical average for the Gulf of Mexico.[33] The liquids are taken to be in proportion to those produced from Louisiana gas during 1975.[34]

4.3.6 Water Requirements

Water for offshore production platforms may be required for both process cooling and domestic and sanitary use. Cooling requirements vary widely and may be extensive or nonexistent. When cooling is required, direct or indirect seawater cooling, or even air cooling, may be used. Seawater cooling requires the maintenance of a very low flow velocity (about 5-8 ft/sec) to prevent corrosion. Air cooling requires a larger deck area, but may be an attractive alternative for cooling requirements less than 50×10^6 Btu/hr.[35] No data is available to estimate possible water usages for cooling, but the impact from such usage at the low velocities indicated is judged to be extremely small.

The water usage assumed for both offshore and onshore domestic and sanitary purposes is 50 gal/day per person.[36] Also, the onshore processing plant may use about 120,000 gal/day for cooling purposes in addition to its domestic or sanitary uses.[37] It is assumed that 5% of the cooling water and all of the domestic water is consumed.

4.3.7 Land Requirements

Land requirements for offshore production of natural gas include areas for construction of production platforms, for the onshore gas-processing plant, and for docking and storage facilities necessary to support exploration, drilling, and pipeline construction.[38] Table 4.4 summarizes the land requirements and the estimated amount of the time needed.

Temporary land uses for the reference system are assumed to be 2350-4600 acre-years. Permanent land use, that used during the entire production lifetime, is expected to be 155-157 acres.

Table 4.4. Summary of Offshore Reference System Land Requirements

Activity	Area (ac)	Duration (yr)
Geophysical Surveys and Support	10	1
Exploratory Drilling Support	5	2.5
Platform Construction	1500 - 3000	1.5
Platform Installation Support	60	0.5
Development Drilling Support	15	2.5
Pipeline Construction Support	10-20	0.5
Production Support	5-7	Economic Life
Gas Processing Plant	150	Economic Life

Source: Office of Technology Assessment, *Coastal Effects of Offshore Energy Systems*, p. 145 (estimated in part) (Nov. 1976).

4.3.8 Employment

Direct employment associated with the development and operation of the reference offshore system has been derived from employment data for oil and gas operations in the U.S. and the Gulf of Mexico.

Employment requirements are based on the following development timetable:

All pre- and post-lease geophysical reconnaissance is assumed to be within one year surrounding the lease sale. As a result of the lease sale, eleven nonassociated gas traps are discovered; these traps compose the reserve base for three production units.

Exploratory drilling associated with each production unit takes 24 months to complete. For the first unit, it commences directly after completion of all geophysical exploration; initiation of operations for the second and third units is phased at six-month intervals and these each require 24 months to complete.

Construction of the three production units is a series of operations each requiring six months to complete, with construction of the first unit beginning 16 months after the exploratory drilling begins.

Installation of the platforms at each production site takes two months to complete. Thus, each unit is completed and installed at the same time as that unit's exploratory drilling program ends.

Installation is followed by 18 months of development drilling.

Production begins after all wells on a given unit are completed.

Gathering and transmission pipelines are layed beginning immediately after the installation of each production unit. Four months are required for each operation.

The pre- and post-lease geophysical evaluation associated with the acquisition of 33 offshore tracts and the discovery of eleven traps requires an estimated 100 crew-weeks of activity within one year surrounding the lease sale. Gulf weather conditions are favorable for this activity only 35 weeks per year,[41] and thus 3 seismic crews would be required. Each crew is composed of 21 persons -- a technical crew of 15 and a ship crew of six persons.[42] Thus, a total of 63 geophysical evaluation personnel are required.

The exploratory drilling associated with each of the three units requires the services of 238 persons. These persons make up two offshore crews of 102 persons each and 34 shore support personnel. Each offshore crew works on a schedule of 7 days on and 7 days off.[43]

Although the actual lead and fabrication time for a self-contained production platform capable of operating in 250 ft of water may range from 8 to 15 months, the actual fabrication time is typically about 6 months. Fabrication of each production unit requires about 1200 man-months or 200 persons. Installation requires 120 persons.[44]

Development drilling for each unit requires the same level of employment as exploratory drilling -- 238 persons. Drilling operations are estimated to take 18 months for the 22 development wells (production plus dry) drilled per production unit.[45] Although more and deeper wells are needed during the development drilling program, the required length of time is shorter and level of employment is the same as for the exploratory program. This time advantage accrues as a result of drilling from a fixed rather than a floating platform, and of having a better understanding of the underlying strata during the development phase. Each pipeline construction phase will require about 100 persons,[46] and once production begins, 24 platform personnel and 18 processing personnel are needed for each of the three units.[47,48]

Throughout the development and operational phases, an estimated seven persons per unit occupy general administrative positions.

By the end of the 5.5-6.5 year development phase, a total of 3127 man-years of effort would be expended for development and administration.

Peak employment would occur during the installation of the first and second platforms with the employment of 1055 persons. After reaching peak employment in the third and fourth years, development employment would drop off and operational employment would phase in during the second half of the fifth year. By the middle of the sixth year all construction and development would be complete, and a total of 147 operational personnel would be employed over the production lifetime. Figure 4.4 summarizes the developmental and operational workforce estimates.

4.3.9 Construction and Operating Costs

Construction Costs. Capital construction costs include both the direct and indirect costs of acquiring lease property, performing necessary geological and geophysical exploration, drilling exploratory and development wells, purchasing and launching production platforms, and laying necessary pipelines. These costs, based on the characteristics of the reference system, are summarized in Table 4.5.

The largest single direct cost is that associated with the lease acquisition. Each reference system lease is assumed to be acquired at $2500/acre and contains 5000 acres -- thus the bonus paid per lease would be $12.5 million.[49] Itemizing these costs in millions of dollars: thirty-three such acquisitions would amount to 412.5; geophysical exploration and exploratory drilling, to 47.6; development drilling, 69.3; platform purchase and installation, 66.0; and pipelines, 6.2; totaling direct capital costs for the reference offshore system at $601.6 million -- all costs are expressed in constant 1975 dollars.

In addition to the direct capital costs, a general and administrative overhead cost is associated with oil and gas development. From data available in the Joint Association Survey,[50] exploration overhead accounts for an additional 4.54% of the lease acquisition, geological and geophysical exploration, and exploratory drilling costs. Overhead associated with the development activities of platform and pipeline installation and development drilling adds 6.47% of those costs. Thus, exploratory and development overheads of $20.9 million and $9.2 million, respectively, are estimated as part of the indirect

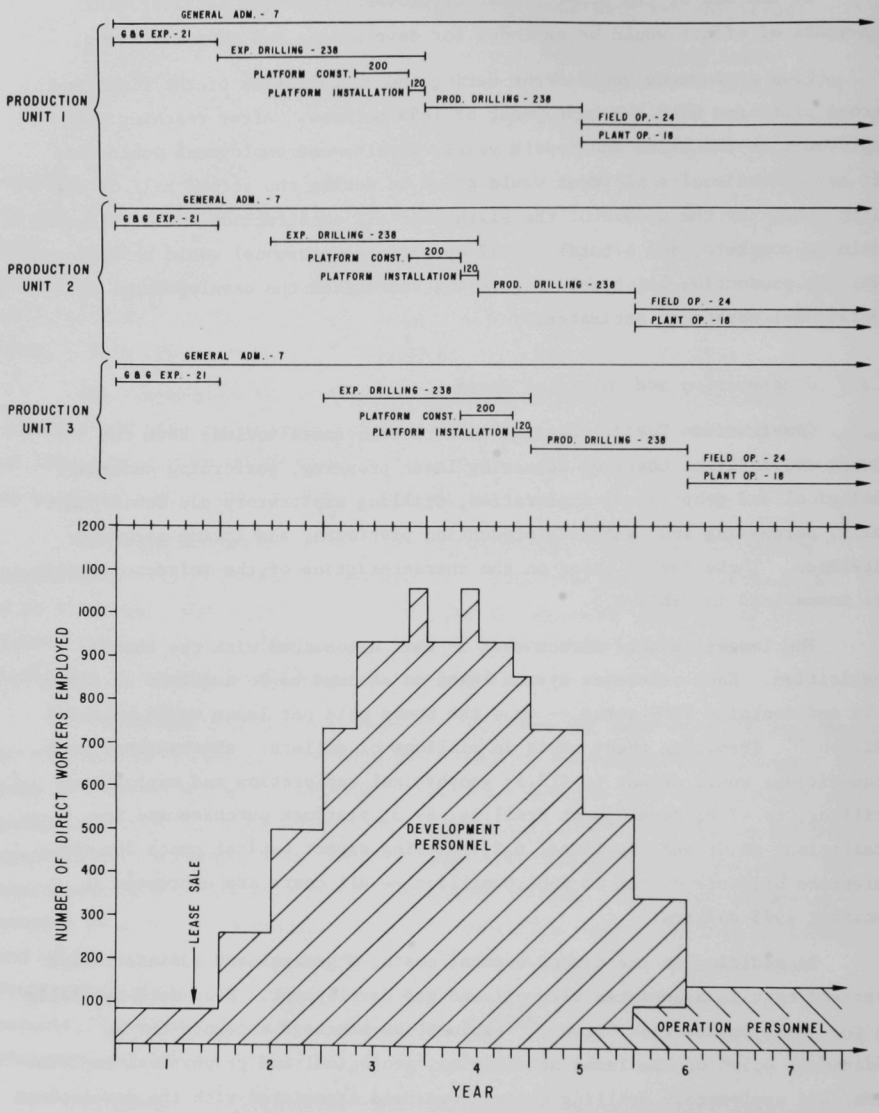


Fig. 4.4. Offshore Reference System Development and Operation Work Force

Table 4.5. Offshore Reference System Capital Costs

Component	Description	Cost Million 1975$
Direct:		
Lease Acquisition[a]	33 tracts @ $12.5 million each	412.5
Geological and Geophysical Exploration[b]	3 crew-years @ $1.73 million/ crew year	5.2
Exploratory Drilling[c]	50 wells @ $0.848 million each	42.4
Development Drilling[d]	47 producers @ $1.098 million ea.	51.6
	19 dry @ $0.932 million each	17.7
Platforms[e]	3 main units @ $12 million each	36.0
	6 satellite units @ $5 million ea.	30.0
Pipeline[f]	31 miles @ $0.20 million/mile	6.2
Total Direct		601.6
Indirect:		
Exploratory Overhead[g]	4.54% (412.5 + 5.2 + 42.4)	20.9
Development Overhead[g]	6.47% (51.6 +17.7 + 36.0 + 30.0 + 6.2)	9.2
Interest During Development		57.4
Total Indirect		87.5
Total Capital Cost		689.1
Capital Cost Assignable to Natural Gas Production	689.1 x .91	627.1

[a]Based on 5000-acre tracts and a $2500 bonus per acre.

[b]BDM Corporation, *A Study of New Use Demands on the Coastal Zone and Offshore Areas of New Jersey and Delaware*, Vol. 2, p. iv-22.
MIT, *Primary, Physical Impacts of Offshore Petroleum Development*, p.21.

[c]American Petroleum Institute, *Joint Association Survey Section I: Drilling Costs* (1970-1974). Average 1974 offshore Louisiana dry hole cost was $85.64/ft. A 1975 cost was estimated by applying the 5-year averaged escalation rate. Thus:

8,395 ft/well x $85.64/ft x 1.18 = $0.848 million/well

[d]American Petroleum Institute. Average 1974 offshore Louisiana gas well cost was $94.05/ft. A 1975 cost was estimated by applying the 5-year averaged escalation rate. Thus:

10,620 ft/well x $94.05/ft x 1.10 = $1.098 million/well

Dry hole costs are based on 9900-ft wells and cost per foot as in (c).

[e]Main unit costs based on personal communications with R. Rice, Brown and Root Co., Houston, Texas; satellite unit costs estimated in part.

Table 4.5. Footnotes (Cont'd)

[f]Bureau of Land Management, *FEIS OCS Sale 44*, p. III-63; an average construction cost of $200,000/mile was used rather than the $150,000/mile cited by the BLM.

[g]American Petroleum Institute, *Joint Association Survey Section II: Expenditures for Exploration, Development and Production* (1974), Table 1.

capital investment. Interest on capital funds used during construction, calculated at the historic constant dollar rate of 3% adds another $57.4 million for a total capital investment of $689.1 million in constant 1975 dollars.

In accordance with FPC procedures, as expressed in Opinion Nos. 770 and 770-A, 9% of all costs are assignable to gas liquids production and 91% to the production of natural gas. These percentages are founded upon the relative economic values of these products.[51]

Operating Costs. Direct and indirect operating costs for 1975, in that year's dollars are estimated at $7.6 million. These charges, itemized in Table 4.6, include labor, food, transportation, equipment maintenance, administrative and insurance overhead, and other operating necessities; a 16.7% royalty levied on gross revenues is also recognized. Again, only 91% or $6.9 million are assignable to natural gas production. These costs are assumed to escalate at 1.5% above an annual inflation rate of 6%. As indicated in Table 4.6, the 15-year levelized annual cost for operation and maintenance is $8.5 million for a production operation starting in 1985.

Required Income and Prices. An analysis of 30 major oil companies, 17 of which account for 92.2% of the total offshore production of natural gas, has indicated an average debt-equity mix of 28:72%.[52] Petroleum bond issues by these corporations have current dollar yields of 9%, and most consider current dollar return on equity to be about 15%. These data, as well as a marginal federal income tax rate of 48%, a production tax of 16.7% on gross revenues, and a 15-year service life, were assumed for the reference system.

Table 4.6. Offshore Reference System Annual Operating Costs

Component	Annual Cost (10^6 1975$)
Direct:	
Labor	1.3
Food	0.2
Transportation	1.1
Equipment Maintenance	0.5
Workover	1.7
Other	0.1
Total Direct	4.9
Indirect:	
General and Administrative Overhead	0.1
Insurance	2.6
Total Indirect:	2.7
Total	7.6
Cost Assignable to Gas Production (91%)	6.9
Levelized Annual Operating Cost (1985 Start-up)	8.5

Derived from: Arthur D. Little, Inc., *Economic Analysis of Proposed and Interim Final Effluent Guidelines of the Offshore Oil and Gas Producing Industry* (Ref. 27), pp. IV-13 to IV-15 (n.d.).

Revenue requirements and prices were calculated on a constant 1975 dollar basis and assume a 1985 start-up. An underlying inflation rate of 6% was used, and annual operation and maintenance costs were assumed to escalate at an annual rate of 1.5% above inflation. Annual required revenue for the gas production portion of the reference system is thus $146.46 million. Unit production costs are $1.61/Mcf* or $1.57/MMBtu.

The national rate ceiling for interstate gas sales is currently $1.42 per Mcf. However, the FPC has recently approved rates of $1.44 and $1.52 per Mcf for two offshore Gulf of Mexico projects.[53] Additionally, an FPC administrative law judge has granted preliminary approval for a rate of $1.60 for an offshore project (this ruling is subject to Commission review). Others have applied for special relief from the national rates, asking for as much as

*Mcf = 1000 cubic feet

$2.05 and $2.37.[54] Thus, an estimated sale price of $1.61/Mcf for the reference system is within an acceptable range of prices for similar sources of gas.

4.3.10 Summary of Offshore Reference System Parameters

The more significant physical and cost parameters associated with the offshore reference system are summarized in Table 4.7. Residuals associated with this system are discussed in the following section.

4.4 RESIDUALS

4.4.1 Air

Air pollutants from the production of natural gas from the offshore reference system result primarily from three emission sources: venting or loss of gaseous hydrocarbons from the lease and processing plant; flaring of gaseous hydrocarbons from these locations; and emission of exhaust gases from compressor stations and electrical generating unit:

The following assumptions, based on the reference system characteristics, were used to calculate the residual air emissions:

1. 25% of the vented or flared gas from both the lease operations and the processing plant is emitted without burning (vented).

2. All gas from the processing plant that is lost or unaccounted for is emitted to the atmosphere without burning.

3. Gas vented, lost, or unaccounted for is composed of 92.5% methane, 4.7% ethane, 1.3% propane, 0.8% butane, and 0.6% pentane. The density of this mixture is about 0.046 lb/cf.

4. 75% of all "vented or flared" gas is flared. Emissions are based on EPA emission factors for gas combustion in electric utility boilers.[55] A total sulfur content of 0.2 grain/100cf (0.3 lb/MMcf) of flared gas is assumed.

5. Hydrogen sulfide concentration in the raw and processed gas stream is 0.1 grain/100cf (0.15 lb/MMcf).

Table 4.7. Summary of 250 MMcfd Offshore Reference System Characteristics

Field and Processing Flow Rates, MMcfd	
Gross Withdrawal	285.30
Vented or Flared in Field	0.39
Lease Fuel Use	11.70
Process Plant Input	273.21
Vented or Flared from Plant	0.25
Lost or Unaccounted for	1.37
Extraction Losses	13.43
Plant Fuel	8.16
Average Daily Sendout	250.00
Heating Value (delivered gas), Btu/cf	1024
Number of Tracts Leased (5000 acres ea)	33
Geophysical and Geological Exploration, crew-weeks	100
Exploratory Wells	50
Production Units (3 platforms ea)	3
Main Platforms	3
Satellite Platforms	6
Development Wells	
Producers	47
Dry	19
Pipelines	
Gathering, mi	10
Transmission, mi	21
Consumptive Water Use, gpm	6.0
Land Requirements:	
Temporary, ac/yr	2345-4600
Project Lifetime, ac	157
Development (Construction) Period, months	66-78
Development Man-years	3127
Operating Workforce	147
Costs, million 1975 dollars	
Direct Development	$547.5
Indirect Development	27.4
Interest During Construction	52.2
Total	$627.1
Levelized Annual Operation and Maintenance	$ 8.5
Capital Component of Delivered Cost, $/Mcf*	$ 1.51
Operation Component of Delivered Cost, $/Mcf	.10
Total, $/Mcf	$ 1.61
Energy Costs @ 1024 Btu/cf, $/MMBtu*	$ 1.57

*Note: Mcf = thousand cubic feet; MMBtu = million British thermal units

6. Because of the low concentration of sulfur and hydrogen sulfide in gas recovered from the Gulf of Mexico, cleaning (or scrubbing) is not required.

7. Gas consumed as lease and plant fuel is burned in gas turbines. EPA emission factors for electric utility gas-fired turbines are used to estimate the emissions from these sources.[56]

Table 4.8 summarizes the estimated annual air emissions for the reference offshore system based on these assumptions.

4.4.2 Water

Residual water pollutants from the operation of the reference system are primarily a result of the offshore gas recovery operation. The principal source of offshore water pollution is the disposal of formation waters, which are generally produced along with the desired hydrocarbons. Other sources of offshore water pollution are deck drainage and sanitary and domestic wastes.

Table 4.8. Annual Air Emissions from Operation of the Offshore Reference System (tons/yr)[a]

	Field			Plant			Composite			
Pollutant	Vent	Flare	Fuel	Vent	Flare	Fuel	Vent	Flare	Fuel	Total
Particulates	-	1	30	-	1	21	-	2	51	53
NOx	-	37	882	-	24	615	-	61	1497	1,558
SOx (as SO_2)	-	b	1	-	b	1	-	b	2	2
Hydrocarbons	818	b	90	12,025	b	63	12,843	b	153	12,996
CO	-	1	245	-	1		-	2	416	418

[a] H_2S emissions less than 0.05 tons/yr.

[b] Less than 0.5 tons/yr.

The chief impediment to characterizing the amount of residual resulting from the disposal of formation waters is the wide variation of such waters with regard to flow rate and chemical content. Wells in the initial state of production may have formation waters that represent 20-30% of the total extractable fluid. As the hydrocarbon reservoir is depleted, the relative amount of formation water generally increases. Furthermore, the chemical characteristics of the formation waters can change during production as additional wells are tapped or leakage occurs between reservoirs.[57] However, most formation waters will contain some materials such as cyanide, cadmium, chromium, lead, and mercury.

A representative value for the amount of formation water produced per million cubic feet of gas may be obtained from the data in Table 4.9. By using the midpoints of the column and row ranges and applying the occurrence probability of each column-row combination to those midpoints, a representative value of 24.5 bbl/MMcf can be obtained. The maximum value shown in the table is about 160 bbl/MMcf.

In addition to highly variable flow rates, the chemical constituents of the formation waters may vary over a wide range. Table 4.10 shows the solids concentrations of representative offshore formation waters classified as having high, average, and low concentrations of solids, and Table 4.11 shows the results of a 1974 EPA survey of 25 discharges in Louisiana and Texas coastal waters.

The reference offshore system is assumed to produce an average of 25 barrels of formation water with every million cubic feet of gas. Thus, a gross production of 285.3 MMcfd results in a total of 7150 bbl of formation water daily. These waters are assumed to have the following concentrations of pollutants.

Pollutants	mg/l
Oil and Grease	30
BOD	234
COD	382
Total Dissolved Solids	140,000
Total Suspended Solids	100

Table 4.9. Average Daily Gas and Formation Waters Produced in Federal Waters Offshore Louisiana (% of 199 Platforms Sampled)

Avg. Water Produced (B/D)	0-20	20-50	50-100	100-200	200-500	500-1000	1000-2000	2000-5000	% of Total	Cum % Total
Avg. Gas Production (MMcfd)										
0-.12	1.5	0.5	-	-	-	-	-	-	2.0	2.0
.12-.30	2.0	-	-	-	-	-	-	-	2.0	4.0
.30-.60	0.5	-	0.5	1.0	0.5	-	-	-	2.5	6.5
.60-1.20	0.5	0.5	-	-	-	-	-	-	1.0	7.5
1.20-3.00	8.5	0.5	1.0	-	1.0	-	-	-	11.0	18.5
3.00-6.00	12.1	2.0	0.5	0.5	0.5	-	-	-	15.6	34.1
6.00-12.00	10.1	1.5	1.5	0.5	1.5	0.5	0.5	-	16.1	50.2
12.00-30.00	12.1	2.0	2.0	1.5	5.1	1.5	-	0.5	24.7	74.9
30.00-60.00	4.6	2.5	1.5	1.5	2.0	0.5	0.5	0.5	13.6	88.5
60.00-90.00	2.5	-	0.5	1.0	0.5	1.0	1.0	-	6.5	95.0
90.00-120.00	0.5	-	-	-	-	-	-	-	0.5	95.5
120.00-180.00	1.0	0.5	-	-	0.5	0.5	-	-	2.5	98.0
180.00-240.00	0.5	-	-	-	-	-	0.5	0.5	1.5	99.5
240.00	-	-	-	-	-	-	0.5	-	0.5	100.0
% of total	56.4	10.0	7.5	6.0	11.6	4.0	3.0	1.5		
Cum % of total	56.4	66.4	73.9	70.9	91.5	95.5	98.5	100		

Source: Ref. 27, p. V-11

Table 4.10. Chemical Content of Representative Offshore Brines (Offshore Louisiana)

	Solids					
	High		Average		Low	
Component	mg/l	%	mg/l	%	mg/l	%
Iron	153	0.057	15	0.011	139	0.226
Calcium	17,000	6.287	4,675	3.294	772	1.254
Magnesium	2,090	0.773	1,030	0.726	152	0.247
Sodium	84,500	31.250	49,120	34.612	22,651	36.800
Bicarbonate	37	0.014	100	0.070	933	1.516
Sulfate	120	0.044	0	0	188	0.305
Chloride	166,500	61.575	86,975	61.287	36,717	59.652
Total	270,400	100%	141,915	100%	61,552	100%

Source: U.S. Geological Survey, Oil and Gas Supervisor, Gulf of Mexico Area. New Orleans, La. Quoted in BLM Lease Sale 41, *FEIS*, p. 448.

Table 4.11. Results of 1974 EPA Survey of 25 Gulf of Mexico Formation Water Discharges

Pollutant	Offshore Louisiana Range (mg/l)	Offshore Texas Range (mg/l)
Oil and Grease	7 - 1300	
Arsenic	-	0.01 - 0.02
Cadmium	0.005 - 0.01	0.02 - 0.193
Chromium	-	0.10 - 0.23
Copper	-	0.10 - 0.38
Lead	-	0.01 - 0.22
Mercury	413	0.001- 0.13
Nickel	-	0.10 - 0.44
Silver	-	0.01 - 0.10
Zinc	-	0.10 - 0.27
Phenolic compounds	-	53
Total organic carbon	30 - 1580	-
BOD	-	126 - 342
COD	-	182 - 582
Chlorides	-	42,000 - 62,000
Total dissolved solids	32,000 - 202,000	806 - 169,000
Total suspended solids	22 - 390	12 - 656

Source: Halper, M., *Development Document for Interim Final Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Segment of the Oil and Gas Extraction Point Source Category*, U.S. EPA p.43,46 (Sept. 1975).

The oil and grease effluent is based on the final effluent limitations proposed by the EPA for OCS oil and gas production units. The proposed limitations call for a one-day maximum oil and grease effluent concentration of 52 mg/l and a 30-day average of 30 mg/l.[58] The remaining effluent concentrations are based on the EPA surveys and USGS data as presented in Tables 4.10 and 4.11. Table 4.12 summarizes the annual residuals resulting from disposal of the formation waters associated with the reference system.

Sanitary and domestic waste volumes are estimated at 50 gal/day/man.[59] The assumption of 24 field employees for each of the three production units will result in a discharge of 3600 gal/day of sanitary and domestic wastes. These discharges are assumed to have 35 mg/l BOD, 45 mg/l suspended solids, and 1.75 mg/l residual chlorine.[59,60] Table 4.12 also summarizes the estimated annual water residuals resulting from this source.

Table 4.12. Annual Water Residuals from the Offshore Reference System (tons/yr)

Pollutant	Formation Waters	Domestic and Sanitary
Oil and Grease	14	-
BOD	107	0.2
COD	175	-
Total Dissolved Solids	70,520	-
Total Suspended Solids	45	0.25
Residual Chlorine	-	0.009

4.4.3 Solids

Each person employed on the production units and processing plant will generate an average of 5 lb/day of domestic solid wastes. Thus, the 72 offshore employees will produce 66 tons of solid waste annually; onshore personnel in the processing plant and administrative positions will generate about 69 tons/yr for a total of 135 tons/yr.

4.4.4 Occupational Health and Safety

In 1970 through 1975, a total of 89 fatalities resulted from oil- and gas-related activities on the Outer Continental Shelf. Also during this period, 18.36 tcf of natural gas was marketed from producing wells on the OCS.[61]

By assuming that the fatality rate can be assigned to oil or gas production by the relative number of operating wells during 1972, 34.9% of these deaths can be attributed to gas production.[62] Marketed production from the reference system is 0.099 tcf/year (273.21 MMcfd). Thus, an estimated 0.169 fatalities will occur per year in the offshore operations associated with the reference system. Each fatality is assumed to be equivalent to 7500 man-days lost, based on an estimated average platform worker age of 35.

In the 1968-1969 period, an average of 10.09 nonfatal injuries per million man-hours labored resulted from oil and gas production activities. These incidents were responsible for the average loss of 46 man-days of labor

per injury.[63] Each production worker is assumed to work 3500 hours per year. Thus, 2.543 nonfatal injuries resulting in the loss of 117 man-days of labor could be expected from offshore activities.

The reference system also assumes employment of 75 onshore personnel. These persons working 40 hours per week for 50 weeks per year would provide 150,000 man-hours of effort per year. Applying nationwide accident statistics for natural-gas processing plants during 1968 and 1969 indicates that there is an 0.0135 probability of fatality per year and 1.278 nonfatal injuries per year as a result of operating the reference-system plant.[64] Each fatality results in a loss of about 6200 man-days; each accident accounts for the loss of 32 man-days. Table 4.13 summarizes the annual occupational injury and fatality rates for the reference system.

Table 4.13. Annual Injury and Fatality Rates for the Offshore Reference System

Incident	Offshore Operations	Processing Plant & Adm.	Total
Fatalities	0.169	0.0135	0.183
Injuries	2.543	1.278	3.821
Man-days lost	1384	125	1509

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5 IMPORTATION OF LIQUEFIED NATURAL GAS

5.1 BACKGROUND AND CURRENT STATUS[1,2,3]

Commercial interest in natural gas liquefaction to reduce its volume for convenient transportation and storage began in 1914 with the first patent applications for liquefaction, storage, and barge transportation of natural gas. A prototype liquefaction plant was built soon thereafter but shut down in 1921 because of insufficient market development. (In 1924, the U.S. Bureau of Mines incorporated liquefaction and cryogenic separation to extract helium from natural gas. By 1937, this process had attained widespread commercial availability.)

By the early 1940s gas utilities in West Virginia and Ohio were applying the liquefied natural gas (LNG) technology as a means of meeting peak demands. The West Virginia facility, a pilot plant built by Hope Natural Gas Company, had a liquefaction capacity of 300 thousand cubic ft per day (Mcfd) and a storage capacity of about 55 cubic meters liquid (m_ℓ^3) -- equivalent to 1.2 million cubic ft of gas. The Cleveland, Ohio, plant, built by East Ohio Natural Gas Company, had a liquefaction capacity of 4 million cubic ft per day (MMcfd) and an original storage capacity of 2500 m_ℓ^3. Storage capacity was increased after 2-1/2 years of operation by the addition of a 4500 m_ℓ^3 tank. In 1944 this tank failed; a disastrous fire ensued that resulted in numerous fatalities and heavy property losses. The cause of the failure is thought to be a combination of improper tank design and the use of an alloy unsuited for extremely low temperature service.

This disaster temporarily diminished utility interest in LNG. In 1965 four LNG peak shaving facilities commenced operation. These facilities, located in California, Alabama, New Jersey, and Wisconsin, have an aggregate liquefaction capacity of 14.4 MMcfd, a regasification capacity of 114.0 MMcfd, and a storage capacity of 189,000 m_ℓ^3 (4,200 MMcf gas). As of June, 1976, 46 LNG peaking shaving facilities were operating in the United States; combined liquefaction capacity totaling 260 MMcfd, regasification capacity 918 MMcfd, and combined storage 2.4×10^6 m_ℓ^3 (52,670 MMcf gas).

In 1949 the Union Stock Yard and Transit Company of Chicago started investigations into river transportation of LNG by barge. Although the barges

developed were unsatisfactory, later investigations led to the design and construction of the first vessel to be used for intercontinental shipment of LNG, the *Methane Pioneer*.

The *Methane Pioneer* was converted from a dry cargo vessel to carry 5000 m^3_ℓ of LNG (110 MMcf) between Lake Charles, Louisiana, and the United Kingdom. Shipments began in early 1959 and by March, 1960, seven voyages and one year of continuous operation were completed and the successful demonstration of transoceanic LNG transportation was proven.

In 1972, a total of 14 LNG tankers were operating. By 1974 the number of vessels operating, under construction, or planned totaled 99 vessels. Of this number, 31 were vessels of 125,000 m^3_ℓ or greater capacity.

Successful demonstration of transoceanic shipment of LNG led to the establishment of the world's first baseload natural gas liquefaction plant for international trade. The *Camel* plant at Arzew, Algeria, began deliveries to the United Kingdom and France late in 1964. Two additional baseload liquefaction plants were placed in operation in 1969 and 1970; one at Kenai, Alaska, for export to Japan, and one at Marsael-Brega, Libya, for export to Italy and Spain. Three plants became operable between 1972 and 1975. Two of these, *Sonatrach* Phase I and Phase II became operable in 1972 and 1975 at Akikda, Algeria, respectively, while the third, Brunei LNG began operation in 1973 at Lumut, Borneo. The *Sonatrach* facility is currently exporting to France and the United States, while the Brunei facility exports to Japan.

Aggregate liquefaction capacity of plants now in operation is 2025 MMcfd. As of mid-1976, Algeria was constructing three additional liquefaction facilities for a combined capacity of 2450 MMcfd projected to become operable before 1980. Indonesia and Abu-Dhabi are also considering gas liquefaction facilities with a total capacity of 2100 MMcfd, also to become operable by 1980.

LNG was first imported to the United States in 1968 when an emergency shipload was purchased by Boston Gas Company from the *Camel* plant in Algeria. Since then, there have been further imports of LNG from Algeria to Boston Gas Company, Distrigas, and Texas Eastern. Several small imports by tank truck into New England from liquefaction facilities operated by Gaz Metropolitan in Montreal have also taken place.

As of June, 1976 there were four LNG import terminals operating in the United States, and two others were under construction. Storage and regasification capacities for these are listed in Table 5.1. The combined regasification capacity of the operating plants is 1995 MMcfd; aggregate storage capacity is 6 million barrels (965,000 m_ℓ^3).

In addition to the U.S. LNG import terminals, ten other terminals are operating in the United Kingdom, France, Spain, Italy, and Japan. World storage capacity, excluding the United States is nearly 10 million barrels (1.59 million m_ℓ^3). Associated regasification capacity is 2747 MMcfd.

5.2 *OVERVIEW OF THE LNG TECHNOLOGY*

Upon liquefaction, natural gas (∿95% CH_4) is cooled to -259°F (-162°C) and reduces in volume by a factor of 625. Because increased pressure has only little effect on the liquefaction temperature, liquefaction and storage of natural gas is generally at or near atmospheric pressure.

Table 5.1. LNG Import Terminals Operating or under Construction in the U.S.

Company	Site Location[a]	Storage Capacity (thousand m_ℓ^3)	Regasification Capacity (MMcfd)
Distrigas Corp.	Everett, Mass.	155	135
Algonquin LNG Inc.	Providence, R.I.	286	300
Public Service Elect. & Gas Co. of New Jersey	Staten Island, N.Y.	286	360
Columbia LNG Corp. & Consolidated System LNG Co.	Cove Point, Md.	238	1200
Northwest Natural Gas Co.	Newport, Ore. (U.C.)	55	100
Southern Energy Co.	Elba Island, Ga. (U.C.)	191	540

[a]U.C. = under construction as of June 1976.

Source: *LNG Scoreboard*, Pipeline and Gas Journal 23(7):22, (June 1976), cited in Sargent and Lundy Engineers, *Technology Characterization Liquefied Natural Gas*.

Process and storage equipment must be capable of maintaining its integrity at the temperature necessary for liquefying and storing LNG. Generally, temperatures below -240°F are considered cryogenic and special considerations must be given to the design and operation of equipment operating at or below this temperature. The greatest problem is the tendency of structural materials to lose ductility and to become brittle at cryogenic temperatures. Materials such as stainless steel, aluminum, and 9% nickel steels are generally used.[4]

The technology of LNG production and regasification can be conveniently divided into five phases: purification, liquefaction, transportation, storage, and revaporization.

5.2.1 Purification

Before natural gas can be liquefied, any constituents that may become solid at the low temperatures required in the liquefaction process must be removed. In particular, these constituents include water, carbon dioxide, hydrogen sulfide, lubricating oils, and odorants. To control Btu content, removal of the heavier hydrocarbons also may be desirable. High standards of purity are required to prevent hydration or blocking of passages in the liquefaction heat exchangers due to solidification of impurities.

Generally glycol injection and dry desiccant dehydrators are used to remove water. Carbon dioxide and hydrogen sulfide are removed in an amine wash. Contaminants such as dust, compressor oils, natural gas liquids and others are satisfactorily removed with conventional dry mist extractors or centrifugal separators.[5]

An example of the composition of purified gas is presented in Table 5.2. Although variations in the purification process feed may be significant, the purified gas characteristics shown are typical of feed streams to the liquefaction processes.

5.2.2 Liquefaction

Two primary methods are used for liquefaction of natural gas. These are the cascade method and the expander cycle. Two types of cascades can be employed -- the classic or the mixed refrigerant.

Table 5.2. Composition of Purified Natural Gas

Component	Concentration (lb/MMcf)
Methane (CH_4)	41,500.00
Water Vapor (H_2O)	0.04
Hydrogen Sulfide (H_2S)	0.14
Carbon Dioxide (CO_2)	2.00
Nitrogen (N_2)	3,570.00

Adapted from: U.S. Federal Power Commission, *National Gas Survey*, 2:369.

Cascade Methods. A classic cascade uses a number of different refrigerants of successively lower boiling points to cool the natural gas to its liquefaction temperature. Present systems usually use propane, ethylene, and methane as coolants, but other systems have been used and yet others proposed. Typically, the refrigerant with the highest boiling point cools the natural gas and the next refrigerant. This refrigerant further cools the natural gas and the next lower refrigerant. Final liquefaction of the natural gas is usually accomplished by flashing. The flash gas is burned to generate the steam that runs the refrigerant compressors.[6]

The mixed refrigerant cascade (also called incorporated or modified cascade) condenses the feed gas, using a single multicomponent refrigerant. The general process is similar to the classic cascade whereby the feed gas is lowered to its liquefaction point through heat transfer to a successively lower temperature fluid. The essential feature of this cycle is a much simpler piping system and fewer compressors.

Expander Cycle. The expander cycle is widely used in commercial low-temperature refrigeration processes. Here, compressed gas is expanded through turbines that perform the external work. Expansion of the gas provides the cooling effect.

Wide application of the expander cycle to natural gas liquefaction is not expected except for very small capacity operations, primarily because a higher efficiency is achieved with the cascade cycles.[7]

5.2.3 *Transportation*

Two principal types of ocean tanker transport designs are currently in use. These are the free standing (self supporting) and the membrane designs.

Free Standing. With the free standing design, tanks are assembled within the ships hull. These tanks may be either prismatic, vertical cylindrical, or spherical; they may be individually insulated, or insulation may be attached to the inner hull of the vessel. Figure 5.1 shows a free-standing tanker design offered by General Dynamics, Quincy Shipbuilding Division. Each of the five spherical tanks shown measures about 37 meters (120 ft) in diameter, and contains 25,000 cubic meters of LNG. When re-gasified, a single tank produces nearly 552 MMcf of natural gas.

Membrane Design. The membrane design uses the ship's entire hull as an insulated membrane wall. The cargo containment area of these ships is built with a complete double-walled hull (as in the free-standing designs). The inner hull, however, is constructed of material suited for low temperature service and acts as a structural tank. The area between the inner and outer hulls is filled with load-bearing insulation. Containment within the hull is maintained by thin membrane walls vertically subdividing the inner hull.

Two types of membrane walls are generally used for LNG service. In one, the membrane, of either stainless steel or aluminum, has corrugations or a waffle configuration that can accommodate thermal expansion resulting from exposure to a wide range of temperatures. In the other, the membrane is of high-nickel (36%) steel that has an extremely low coefficient of expansion and low modulus of elasticity. These characteristics allow the use of a flat membrane, without corrugations, that can be welded by automatic methods.[8]

General Characteristics. Regardless of containment design, the overall dimensions are similar for transport tankers of comparable carrying capacity. Economically sized tankers range from 50,000 to 165,000 m^3_ℓ; recent considerations have focused on vessels larger than 125,000 m^3_ℓ.

A typical 125,000 m^3_ℓ vessel will be about 900 ft long, with a beam (maximum width) of about 135 ft, and a draft (depth below water line with full cargo) of about 38 ft. Displacement for such a ship is about 95,000 tons, cargo dead weight is about 53,000 tons, and service speeds are between 16 and 20 knots.[9,10]

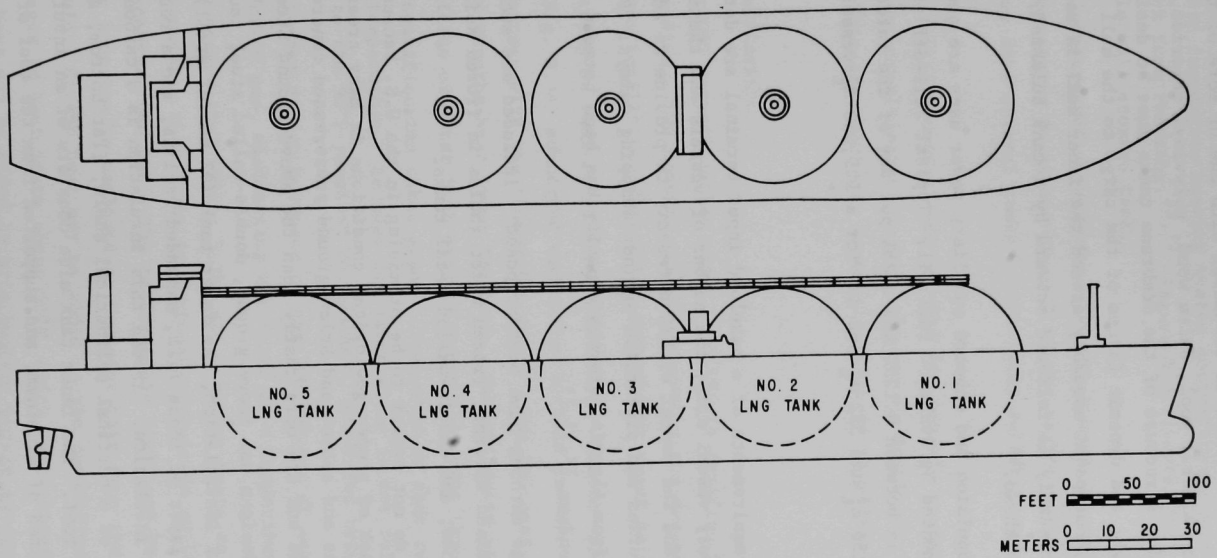


Fig. 5.1. General Dynamics 125,000 Cubic Meter LNG Tanker

The cargo area on tankers is insulated with one or more of the following materials: mineral wool, balsa wood, polyvinyl chloride, or Perlite. The exterior structure of the membrane tanks must be designed to transmit the weight and dynamic forces of the cargo to the hull structure of the vessel; a plywood panel assembly around the inner hull is used for this purpose. The assembly is followed outward by a tank bulkhead, water ballast, and ship bulkhead.[10]

Fuels for propulsion and onboard auxiliary power uses are generally LNG boil-off supplemented by Bunker C fuel oil. Typical boil-off rates for LNG carrier vessels is between 0.125% and 0.25% per day of the rated cargo volume, or between 156 m^3_ℓ and 312 m^3_ℓ per day for a 125,000 m^3_ℓ vessel.[11]

5.2.4 Storage

LNG storage requirements of a baseload input terminal are determined by the maximum delivery vessel size, the number of vessels and their round-trip delivery time, and the amount of LNG necessary to provide an adequate supply between deliveries and protection against shipping delays. For U.S. terminals importing from Algeria, storage capacity has been between 10 and 15 days average plant sendout.[12,13,14]

Various storage methods have been proposed. Included are such concepts as storage in mined caverns, frozen holes (holes in frozen soil), prestressed concrete tanks, and double-walled metal tanks.

Mined caverns do not appear to be promising in the U.S. because of high costs and the lack of proper geological conditions in many areas of the country. Frozen holes and above- and below-ground prestressed concrete tanks have been demonstrated but are more costly than the above-ground steel tank.

Most current designs use above-ground, double-walled steel tanks for storage. In a typical installation, the inner tank (9% nickel steel) is surrounded by a 3-ft layer of loose fill, expanded Perlite, and a resilient fiberglass blanket of insulation. Around this insulation is a carbon steel outer tank consisting of a vertical cylindrical shell, flat bottom, and a self-supporting domed roof. The inner tank also consists of an insulated hanging deck, constructed of aluminum, and supported from the roof of the outer tank. Between the inner and outer tank bottoms are foam-glass blocks

utilized as load-bearing insulation. A concrete foundation supports each tank and an electric foundation heating system automatically prevents the ground under the tank from freezing.[15,16] Figure 5.2 illustrates a typical above-ground, double wall storage tank.

Tanks constructed above ground require a surrounding earthen dike capable of containing in excess of 100% of the tank's maximum contents. Some facilities may dike several tanks collectively rather than construct individual dikes.

Boiloff from a typical 600,000 bbl (95,400 m^3_ℓ) storage tank, about 1 MMcfd during normal operation, may increase to nearly 22 MMcfd during ship unloading. This gas, however, is not lost; it is compressed and sent to the pipeline.[17]

5.2.5 Regasification

In an LNG regasification plant, the LNG is gasified by adding heat via a transfer medium. Two general systems currently are designed for modern regasification facilities; fuel-fired and ambient water bath gasifiers.[18]

Two types of fuel-fired gasifiers exist. In one type of fuel-fired gasifiers (Fig. 5.3a) submerged combustion burners produce a hot-water bath by direct contact with the combustion gases. The LNG heat exchanger is immersed in, and thus absorbs heat from, the bath. Ambient water bath gasifiers use large quantities of water from natural sources to pump through heat exchangers where LNG regasification takes place. The water is then returned to its source at a lower temperature. Because the water alone is not sufficient to warm the gas stream to the 50°F required for sendout, gas-fired trim heaters are used.

One recent design proposes to use 300,000 gpm of seawater to vaporize 1 bcf per day of gas, discharging the water at a temperature drop of 12°F.[19]

In a second type (Figs. 5.3b, c), a heater heats an intermediate fluid such as isopentane, that flows in a closed circuit to an LNG heat exchanger where it vaporizes the LNG. The intermediate fluid may be heated directly or a hot water loop may be employed to transfer heat from the heater to the intermediate fluid. Enough heat may be added to the regasified stream within the heat exchanger to heat it to about 50°F, which is required for sendout, or additional heat may be added by trim heaters before sendout. Generally, part

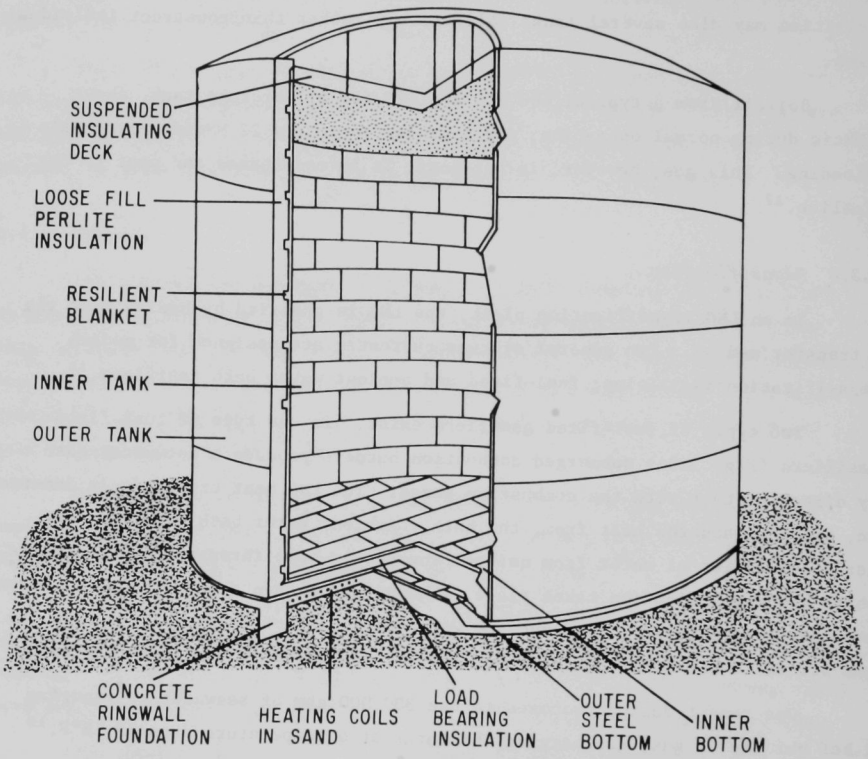
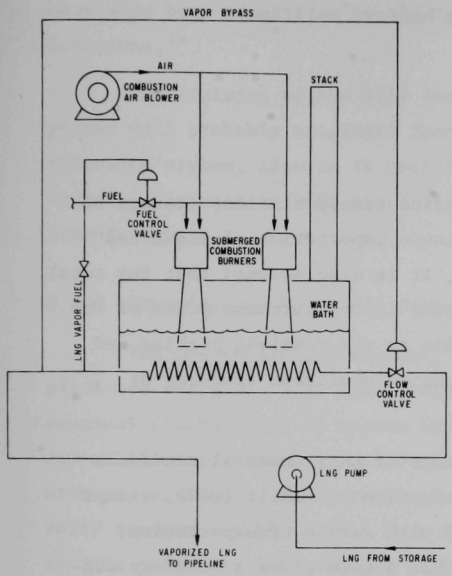
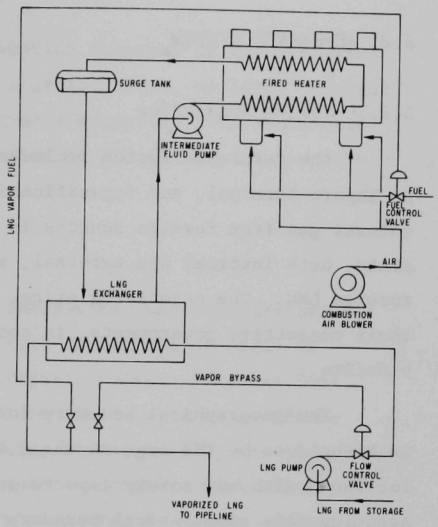


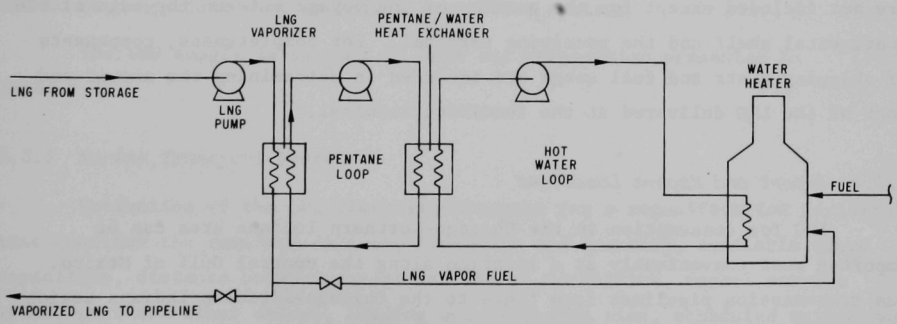
Fig. 5.2. LNG Storage Tank



a. Submerged Combustion



b. Intermediate Fluid



c. Intermediate Fluid with Pentane Loop

Fig. 5.3. LNG Regasification Processes

of the gas stream is used to fire the heaters. In this type of system, exchangers may be located independently of the heater.

5.3 REFERENCE SYSTEM

5.3.1 System Boundaries

The reference system includes only marine transportation, storage at an import terminal, and regasification. Because importation of liquefied natural gas from foreign sources is assumed, it is also assumed that the total costs, both internal and external, are included in the purchase price of the foreign LNG. The negotiated price, acceptable to the involved parties and their respective governments, is considered as an equitable transfer of benefits.

The geographical boundary for assessment of environmental residuals is assumed to be the edge of the U.S. Outer Continental Shelf (OCS), except for the health and safety impacts associated with marine transportation. Assuming this geographical boundary for the LNG system gives a boundary consistent with that for the other gas supply system.

Although with marine transportation of LNG not all crew members of the supporting LNG fleet would be U.S. nationals, health and safety impacts over the entire LNG transportation circuit are included. Environmental residuals are not included except for the portion of the voyage between the edge of the continental shelf and the receiving terminal. For completeness, components of shipping costs and fuel usage are included in determining the amount and cost of the LNG delivered at the receiving terminal.

5.3.2 Import and Export Locations

LNG for consumption in the Chicago-Northern Indiana area can be imported most conveniently at a location along the central Gulf of Mexico. Gas transmission pipelines from there to the Chicago-Northern Indiana region are well established and are of sufficient capacity to handle an incremental increase due to an LNG facility.

A hypothetical site near Lake Charles, Louisiana, is assumed. Ports near this location are of sufficient depth to allow for LNG tankers with drafts

of up to 38 feet. New Orleans and several ports in Texas and Alabama have also been identified by the National Gas Survey as acceptable import locations.[20]

LNG arriving at the Gulf Coast importation terminal in the 1985-1990 period will probably originate from either Algeria, Libya, or Iran. For the reference system, Algeria is used as the primary exporter. The round-trip shipping distance is 9600 nautical miles including 200 miles of outer continental shelf.

5.3.3 *Capacity and Operating Factor*

The LNG receiving terminal, storage facilities, and regasification plant are designed to be baseloaded -- not able to meet major daily or seasonal fluctuations in system load. The regasification plant has four 100-million-cfd, submerged-combustion gasifiers (three service gasifiers with one standby). The overall plant operating factor is 83%, for an average daily sendout of 250 MMcfd. Peak sendout would be achieved with all three service gasifiers operating at full capacity producing a maximum sendout of 300 MMcfd.

Heat would be transferred to the LNG in the gasification train, vaporizing the liquid and heating it to 50°F, the temperature required for sendout. The sendout pressure is assumed to be 1000 psig, which allows the gasified LNG to be compatible with an existing pipeline system.

The LNG supply is assumed to have the composition presented in Table 5.3.

5.3.4 *Marine Transport Vessels*

Estimation of the LNG fleet requirements for a regasification facility must consider the required delivery frequency and quantity, available cargo capacities, distance between export and import facilities, vessel service speed, port and other delays, loading and discharge time, scheduled maintenance, and boil-off losses while in transit.

Voyage Characteristics. The supply of LNG to the reference facility from an Algeria liquefaction plant requires three 130,000-m^3_ℓ, cryogenic transport vessels having a service speed of 18 knots. The average round-trip of 9600 nautical miles is assumed to take 27 days, accounting for cargo handling

Table 5.3. Gaseous LNG Supply Specifications

Component	Concentration
CH_4	95.00 Vol. %
H_2	nil
CO	nil
CO_2	0.005 Vol. %
N_2	5.00 Vol. %
H_2S	0.10 grains/100
Total S	3 grains/100
Heating Value	1015 Btu/cf

Source: FPC, *National Gas Survey*, Vol. 2, p. 369.

and port and other delays. Each vessel is capable of 12 round trips per year and requires 41 days of scheduled maintenance annually. A typical voyage schedule is shown in Table 5.4.

The vessels are assumed to be of the free-standing tank type; all are of U.S. construction. The ships' boilers can use the LNG boil-off vapors as well as Bunker-C fuel oil for propulsion and auxiliary energy generation. Boiloff is used only when in deep seas; fuel oil is used exclusively for propulsion and auxiliary power generation while the ship transverses the U.S. continental shelf and while at port. As vessels are enroute to and from the regasification terminal, they are assumed to cross about 100 nautical miles of continental shelf on each leg of their journey.

Deliverable Capacity. Delivered LNG is somewhat less than the maximum cargo capacity because of losses resulting from LNG boiloff and residual LNG retained in the cargo tanks on the return leg to maintain cryogenic temperatures. And, only about 98% of the total cargo volume can be practically used for cargo.

For the LNG fleet of the reference system, it is assumed that the rated cargo capacity is 98% of the design volume and that the boil-off rate is equivalent to 0.20% per day of the rated cargo capacity. Retained LNG before reloading is taken to be 0.5% of the design volume of 130,000 m^3_ℓ, or 650 m^3_ℓ. Thus, the resulting deliverable capacity is 119,870 m^3_ℓ per shipload.[21]

Table 5.4. Typical Round Trip LNG Tanker Voyage: Algeria to U.S. Gulf Coast

Process	Duration Days
Loan and Discharge Cargo (1 day each)	2
Port Delays (1 day each leg)	2
Loaded and Ballast Legs (11 days each)	22
Other Delays	1
Total	27
Annual Scheduled Maintenance	41

Sources: FPC, *National Gas Survey*, Vol. 2, p. 392.
Johnson, J.P., L.R. Jamison, *Pipeline to Japan - Five Years of History on an LNG Shipping Operation*, Combustion, pp. 33-38 (Feb. 1976).

Requirements for Propulsion and Auxiliary Power. A typical 130,000-m^3_ℓ LNG tanker will have a shaft horsepower (shp) of 50,000.[22,23,24] This power is supplied by steam turbines with an estimated efficiency of 25%. Thus, about 12,200 MMBtu/day of boiler fuel is required for propulsion. A portion of the boiler fuel, about 5713 MMBtu/day is supplied by burning the LNG boil-off vapors. The remainder 6487 MMBtu/day is supplied by Bunker-C fuel oil. About 172 tons/day of Bunker C is needed.

Auxiliary power is estimated to average 82,730 kWh per day generated from a 3.45 MW onboard system. At a 25% conversion efficiency, an additional 30 tons of Bunker-C fuel oil is consumed for this purpose.[25,26]

5.3.5 *Storage Facilities*

Typical LNG storage capacities at baseloaded regasification plants are generally equivalent to between 10-15 days average sendout (2850-4300 barrels per MMcfd). Storage facilities on the reference site would consist of one 600,000 barrel (95,400 m^3_ℓ) and one 300,000 barrel (47,700 m^3_ℓ) double-walled, above-ground storage tank. Each tank has electrical-resistance foundation heaters that automatically maintain ground temperatures under the tanks above 32°F. Each tank is surrounded by an earthen dike capable of containing over 100% of the tank's liquid capacity.

Other onsite storage would consist of 30,000 bbl tank for Bunker-C fuel oil to refuel the LNG transport vessels before their return voyage. The oil is normally maintained at 130°F to facilitate handling.[27]

5.3.6 Docking and Unloading Facilities

The number of LNG tanker berths required depends upon the plant capacity and the arrival frequency of the transport vessels. Voyage characteristics and tanker capacities will require one delivery every ten days. Thus, enough time between deliveries is available to require only one tanker berth. Docking facilities for two tug boats are also needed.

Regardless of send-out capacity, almost all proposed and operating LNG terminals are designed to unload a vessel's LNG tanks in about 12 hours. Unloading is generally through four 16-in diameter unloading arms. A fifth arm is used for returning LNG vapor to maintain a positive pressure in the cargo tanks.[28,29,30]

5.3.7 Auxiliary Energy Requirements

Based on an analysis of recent LNG terminal proposals, electrical energy requirements for storage and regasification of LNG ranges from 570 to 643 kWh/MMcf sendout.[31,32] Thus, a value of 600 kWh/MMcf was selected for the reference system. Assuming that this power is generated onsite with a 33% conversion efficiency, 1.53 MMcfd of gas at 1015 Btu/cf is required to fuel the necessary 6.25 MW of capacity.

Regasification is assumed to be accomplished with submerged combustion gasifiers (efficiency = 88%). Based on the heat input necessary to vaporize the LNG and increase the gas temperature from -259°F to +50°FF (-162 to 10°C) for a sendout of 250 MMcfd, it is necessary to consume 4.88 MMcfd of gas in the submerged combustion units.[33] Thus, a total of 256.4 MMcfd is gasified; 6.4 is consumed in the plant for electrical generation and regasification, and 250 is available for sendout.

5.3.8 Water Requirements

Water requirements for an LNG facility with submerged combustion gasifiers are very small. A recent proposal, designed to regasify an average

of 420 MMcfd has a plant flowthrough of only 100 gpm.[33] As a conservative estimate, it is assumed that the 250 MMcfd reference system will have about the same flowthrough.

Consumptive uses include potable water and restocking of vessel water supplies. Potable water in the plant is estimated to be 5 gpm. Ship requirements amount to about 121,000 gallons per port call.[34] With each of three vessels making 12 calls per year an average of under 8.5 gpm is consumed. Thus, the total water consumption is estimated at less than 11.5 gpm.

5.3.9 Land Requirements

Land requirements for the gasification plant based on areas of other facilities, is about 0.75 acre/MMcfd or 188 acres for the reference system site.

In addition to the regasification site, the vessel docking facilities, also require shoreline and water area. For one berth and associated tug facilities, it is estimated that 22 acres of shoreline and water area are used. Thus, a total of about 210 acres compose the main regasification site and the docking facilities. About 50 acres of the regasification site is occupied by plant facilities.[35-38]

5.3.10 Employment

Based on an analysis of several proposals,[39,40] a 36-month construction period and 500 man-years of effort are required to construct the reference system importation and regasification facility. Annual average employment figures are summarized in Table 5.5.

Table 5.5. LNG Reference System Construction Manpower Requirements

Year	1	2	3	4
Plant	-	150	280	70
Vessels	1000	2000	2000	1000
Total	1000	2150	2280	1070

During the operational phase only 30 persons are necessary to maintain and operate the facility.[41,42]

Each transport vessel is estimated to take 1000 men two years to complete.[43] The total construction period for three tankers is to be four years; 1000 persons are employed during the first and fourth years, and 2000 during the second and third years. Work on the vessels begins one year before plant construction so that the vessels and the plant are completed at the same time. Vessel construction is to be in shipyards near New Orleans.

Operating personnel on each of the three tankers is estimated to be 33 persons -- 11 officers and 22 crew.[44]

5.3.11 Construction and Operating Costs

Construction Costs. Capital costs for the reference system receiving terminal and regasification plant were based on published cost estimates for a 500 MMcfd facility recently proposed by Tenneco LNG Company.[45] The Tenneco costs were adjusted to a 250 MMcfd system by utilizing the cost-size relationship derived by the *National Gas Survey*.[46]

Based on these estimates, the direct construction costs in constant 1975 dollars for a single-berth receiving and regasification terminal is $96.9 million. Indirect costs including insurance, administrative overhead, and other components adds another $24.1 million, and interest during construction (calculated at the historic constant dollar rate of 3%) adds another $8.2 million. Total capital investment in regasification facilities is thus $129.2 million.

Purchase price of each 130,000-m^3_ℓ, cryogenic tanker is estimated to be $160.0 million. This figure was derived from published estimates of recent (1975) orders for similar-sized vessels, and includes the Maritime Administration construction differential subsidy (CDS).[47,48]

Operating Costs. Operating costs for 1975 and in constant 1975 dollars for the reference system receiving and regasification terminal and each of the three LNG tankers are estimated to be $3.9 and $5.0 million annually.[49] Plant and vessel costs include payroll, maintenance, and other charges. These costs are calculated to escalate at 1.5% above an annual inflation rate of 6%. Table 5.6 shows the 20-year, levelized annual cost for plant and vessel operation and maintenance assuming 1985 start-up.

Table 5.6. LNG Importation System Costs

250 MMcfd Receiving Terminal	
Direct Capital Costs	$ 96.9
Indirect Costs	24.1
Interest during Construction	8.2
Total Plant Investment	$129.2
Levelized Annual Operating and Maintenance Costs[a]	$ 5.0
Three 130,000-m^3_ℓ Transport Vessels	
Purchase Price	$480.0
Levelized Annual Operating and Maintenance Costs	$ 19.2
Levelized Gas Purchases	$165.0

[a]Estimate based on in-plant fuel consumption, payroll, state taxes, insurance, and other maintenance charges.

Foreign Gas Purchase Costs. Recently published statistics on newly negotiated LNG contracts with foreign suppliers have indicated an average f.o.b. sale price of $1.30/Mcf of gas.[50] On the average, it is necessary to export 271.38 MMcfd in order to supply 250 MMcfd as regasification plant send-out. Thus, the annual 1975 dollar cost of purchasing the necessary gas supply is $128.8 million. Annual LNG purchase costs are also calculated to escalate at 1.5% above inflation. Thus, the 1975 constant-dollar, levelized annual cost for LNG purchases is $165.0 million for an importation operation beginning in 1985.

Required Income and Prices. The LNG supply option for 1985-1990 is considered as likely to be owned by a natural gas transmission company rather than a large oil company. Gas transmission companies typically have a debt-equity ratio of 60:40%, current dollar bond interest of 9%, return on equity of 15%, and federal income tax rate of 48%.

Assuming an inflation rate of 6%, the after-tax, constant-dollar cost of capital is 10%, and if a 20-year service life is assumed, a constant-dollar, annual capital charge rate of 12% results. Applying this rate to the plant and vessel investments and adding the levelized operation and maintenance and gas purchase costs results in an annual revenue requirement of $262.31 million. Sale price of the product gas (1015 Btu/scf) before transmission would thus be $2.87/Mcf or $2.83/MMBtu.

5.3.12 Summary of LNG Importation Reference System Parameters

Significant physical and cost parameters associated with the reference LNG importation system are summarized in Table 5.7. Residuals associated with this system are discussed in the following section.

5.4 RESIDUALS

5.4.1 Air

Primary sources of air residuals from the LNG reference system include stack gases from the transport vessels while over the outer continental shelf, and flue gases from the plant's submerged combustion gasifiers. Additional pollutants are generated as a result of electrical generation both in the plant and on the transport vessels. A majority of the hydrocarbon emissions originate from storage tank and piping leaks.

The following assumptions have been used to calculate the air residuals from this system.

1. Sulfur concentration of gasified LNG is 3 grains/100 cf (0.01% by weight, 4.29 lb/MMcf). Hydrogen sulfide concentration is 0.10 grains/100 cf (0.00034 % by weight, 0.15 lb/MMcf).
   Sulfur concentration of Bunker-C vessel fuel is 0.2% by weight. (0.02 lb/gal, 4 lb/ton)

2. 4.88 MMcfd of gas is consumed in the regasifier units
   1.53 MMcfd of gas is consumed in plant electrical generation.

3. Only Bunker-C fuel oil is consumed by the vessels while over the continental shelf.

4. 40,500 gallons of Bunker-C fuel oil is consumed by each vessel per round trip for propulsion while over the continental shelf. (81,000 gal/day for 0.5 days)

   18,828 gallons of Bunker-C fuel oil is consumed by each vessel per round trip for electrical generation while docked in U.S. waters. (7,531 gal/day for 2.5 days)

5. Fugitive hydrocarbon losses from the regasification plant are estimated to be 0.01% of sendout capacity.[51] Losses are as CH_4, with a density of 0.0415 lb/cf.

Table 5.7. Summary of 250 MMcfd LNG Reference System Characteristics

A. Receiving Terminal and Regasification Facility:	
Maximum Daily Sendout, MMcfd	300
Operating Factor, %	83
Average Daily Sendout, MMcfd	250
Heating Value, Btu/cf	1015
Number of Service Regasifiers	3
Number of Standby Regasifiers	1
LNG Storage Tanks, bbl	1 - 600,000 1 - 300,000
LNG Feed to Regasifiers, MMcfd - gas	256.41
Gas Consumed for Auxiliary Energy, MMcfd - gas	6.41
Electricity, MW	6.25
Miscellaneous Materials	nil
Consumptive Water Use, gpm	11.5
Land Requirements, Acres	
Regasification Plant Site	188
Plant Site Occupied by Facilities	50
Docking Facilities (1 Berth)	22
Project Construction Period, months	36
Construction man-years	500
Operating Workforce	30
Costs, million 1975 dollars	
Direct Construction	$ 96.9
Indirect Construction	24.1
Interest During Construction (@ 3%)	8.2
Total	$129.2
Levelized Annual Operation and Maintenance	$ 5.0
Levelized Annual Gas Purchase	$165.0
B. LNG Transportation Vessels (each):	
Design Hull Volume, m^3_ℓ	130,000
Rated Cargo Capacity, m^3_ℓ	127,400

Table 5.7. (Cont'd)

Boil-off Losses as Percent of Rated Capacity, %/day	0.20
Boil-off Losses per Delivery, m^3_ℓ	6880
Retained LNG Prior to Reloading, m^3_ℓ	650
Delivered Capacity, m^3_ℓ	119,870
Delivered Capacity as Percent of Design Volume, %	92.21
Number of Vessels	3
Boil-off Feed to Boilers, MMcfd	5.63
Bunker-C Fuel Feed to Boilers, tons/day	
In Transit	172
Docked	30
Electricity, MW	3.45
Miscellaneous	nil
Consumptive Water Use	included in plant use
Algeria-Gulf Coast Voyage	
Round Trip Distance, nautical miles	9600
Vessel Service Speed, knots	18
Average Round Trip Time (including delays), days	27
Trips per Vessel Year	12
Annual Scheduled Maintenance, days	41
Vessel Construction Period, months/vessel	24
Construction Man-years/vessel	2000
Operating Crew	33
Costs, million 1975 dollars	
Purchase Price (includes direct and indirect costs, and accounts for Maritime Administration Construction Differential Subsidy)	$160
Levelized Annual Operating Costs	$6.4
C. Overall System:	
Capital Component of Delivered Cost, $/Mcf	$ .80
Operation Component of Delivered Cost, $/Mcf	.26
Gas Purchase, $/Mcf	1.81
Total, $/Mcf	$2.87
Energy cost @ 1015 Btu/cf, $/MMBtu	$2.83

6. The following EPA emission factors were used:[52]

Source	Emission Factor Category
regasifiers	large gas-fired industrial boilers
plant electrical generation	gas-fired electric utility turbines
vessel propulsion	residual-fired industrial boilers
vessel electrical generation	diesel-powered electrical generators in vessels

Air residuals calculated on these assumptions are presented in Table 5.8.

5.4.2 *Water*

Water residuals from the LNG reference system are very small. Plant flowthrough is less than 100 gpm,[53,54] and no data is available to estimate pollutants added to this stream. Presumably some organics (oil and grease) will be added.

Based on data provided by Hittman Associates,[55] an estimated 5-10 tons per year of organics may be discharged in coastal waters as a result of tanker operations.

5.4.3 *Solids and Sludges*

It is estimated that sanitary and domestic wastes of 5 lb/day for each person employed in the regasification plant and on the transport vessels. Vessel wastes will be stored in an onboard septic system and will be removed at both the import and export locations. Thus, only half of the domestic

Table 5.8. Annual Air Residuals from Operation of LNG Reference System (tons/year)

Air Residual	Transport Vessels	Plant	Total
Particulates	22	13	35
NOx	132	293	425
SOx	29	11	40
Hydrocarbons	14	204	218
CO	12	47	59
Aldehydes	1	-	1

[a] H_2S emissions less than 0.5 tons/year.

wastes generated by the ship's crew are within the system boundary. The annual wastes attributed to the reference system are 45 tons from vessel operations and 27 tons from plant operations. The volume of these wastes is about 90 cu yds.[56]

5.4.4 Occupational Health and Safety

Injuries and fatalities aboard ocean transport vessels result from accidental involvements of the ship (collisions, groundings, etc.) and other onboard personal accidents. Fatalities and nonfatal injuries resulting from accidental vessel involvements have been estimated to be 0.227 and 0.106 per million man-hours, respectively.[57] These data indicate that crew fatalities are more than twice as likely as nonfatal injuries when a ship is involved in a collision, grounding, or other accidents. Onboard personal accidents have been estimated to cause 7.06 nonfatal injuries per million man-hours worked.[58]

The associated disability days (man-days lost) as a result of nonfatal accidents is 57 days. The average crew age is assumed to be 32, so each fatality assumes 8250 man-days lost.

Typically, a ship's crew works an average of 11 hours a day for 324 days each year.[59] Thus, each crew member is assumed to work 3564 hours each year.

Based on 1968 and 1969 data for natural gas processing plants and oil refining operations, the nonfatal accident rate in these industries is 6.46 per million man-hours. Fatality rates are 0.09 per million man-hours. Associated man-days lost from nonfatal and fatal accidents was 52.7 and 6250 days, respectively.[60] These figures have been assumed for the LNG regasification plant, and each of the 30 workers is assumed to work 2000 hours per year.

Table 5.9 summarizes the annual occupational injury and fatality rates estimated for the LNG reference system.

5.4.5 Nonoccupational Human Safety

Nonoccupational fatalities may be approximated based on FPC estimates. Calculations performed by the FPC staff in the Calcasieu LNG project FEIS

Table 5.9. Annual Injury and Fatality Rates for LNG Reference System

	3-Tanker Fleet	Plant	Total
Fatalities	0.0800	0.0054	0.0854
Injuries	2.5284	0.3876	2.9160
Man-days lost	790	54	844

indicate that the probabilities of a fatality per exposed person per year as a result of an LNG vapor cloud ignition or as a result of thermal radiation from an ignited LNG pool are of the order of 10^{-8} and 10^{-6}, respectively.[61] An exposed person is defined as one who resides within the maximum dispersion limits of a vapor cloud or within the area of fatal thermal radiation from an LNG tanker spill. These values are determined by the tanker route, demographic and meteorological characteristics along this route. Maximum spills are generally assumed to be the contents of a single LNG vessel tank, or about one-fifth of the tankers total volume. For a spill along the Calcasieu route, the maximum fatalities from a vapor cloud is estimated at 125, and the maximum number of deaths from a pool fire thermal radiation is 35 persons. FPC estimates for other proposed LNG sites have been of similar orders of magnitude. The probability of death and injury occurring from terminal malfunctions are estimated by the FPC to be significantly less than these values.

If 10,000 man-days are assumed for each fatality, then the man-days lost per exposed person per year can be estimated to be of the order of 10^{-4} to 10^{-2}.

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6 COAL GASIFICATION

Coal gasification has become of increasing interest in the United States because of the declining availability of natural gas from conventional sources and the great abundance of coal in this country. The product sought is a gas with a heating value similar to that of natural gas and thus interchangeable with current pipeline supplies.

6.1 BACKGROUND AND CURRENT STATUS

Commercial production of gas by destructive distillation of coal began in the United States in 1816 with the first coal-gas company in Baltimore, Maryland. Early coal gas was distributed primarily for lighting and had a heating value of between 475 and 560 Btu per cubic foot.

The technology of manufacturing coal gas improved in the United States, and by the late 1930s, nearly every major city in the Eastern United States had its own gashouse where gas was manufactured from coal. After World War II, as natural gas began to be distributed on a nationwide basis by interstate pipelines, the local gashouses gradually disappeared. Burners were redesigned to burn the high Btu natural gas and the market for manufactured gas quickly vanished, halting the further development of coal gasification in the United States.

Coal gasification was developed to a higher degree in Europe where prior to World War II coal was the only indigenous fuel of any significant quantity. But by the time the European technology had advanced to the stage where large numbers of commercial plants could be installed, natural gas was discovered in the North Sea and northern Africa. Also, most European countries were increasingly shifting to lower cost imported petroleum. A few coal gasification plants employing new technological developments were installed but further improvements in the technology faltered.[1,2]

At present there are four gasification processes that have been commercially proven and are available in the United States. These are the Koppers-Totzek, Winkler, Wellman-Galusha, and Lurgi processes. Each of these produce a low- or intermediate-Btu gas that is not interchangeable with pipeline gas unless the methane concentration is increased (and thus the heating value) in a final "methanation" process.[3]

The Lurgi technology appears to be most favored by the U.S. gas industry. The process is well proven, and methane production in the gasifier unit is higher than that in the other processes.[4] Although a full scale methanation stage has not yet been commercially proven, a number of methanation pilot plants and a demonstration plant in Scotland have produced high-Btu gas using the Lurgi process.[5]

In addition to the commercially proven processes, four other designs are under active investigation in the U.S. These include the HYGAS, CO_2 Acceptor, BI-GAS, and Synthane processes. Each of these designs has reached, or is near the pilot plant stage of development.

Fifteen high-Btu coal gasification plants have been proposed or are under consideration in the United States. Ten of these are planned to utilize the Lurgi process with methanation to gasify both western and eastern interior coals. One proposal is considering the HYGAS or a similar process, and the remainder have not yet designated the conversion process to be used.[6]

Economically recoverable coal reserves in the United States were estimated to be about 435.7 billion short tons as of January 1, 1974.[7,8] For the most part, the reserves include deep minable coal to a maximum depth of 1000 ft and strip minable reserves with an overburden of 120 ft or less. Coal seam thicknesses are generally restricted to bituminous and anthracite beds greater than or equal to 28 in. and subbituminous and lignite beds greater than or equal to 60 in. The criteria used by the Bureau of Mines in determining recoverable reserves, however, vary somewhat depending upon local conditions.

About 46% of domestic recoverable reserves are east of the Mississippi River. Of the remainder, 54% are in the western states and Alaska. Of the total reserves, 69% are accessible by deep mining, while 31% may be surface mined. Table 6.1 summarizes U.S. coal reserves by rank and recovery method. Underground coal is considered far too costly and labor-intensive to support a coal gasification plant.

Table 6.1. Summary of Recoverable U.S. Coal Reserves

Mining Method	Rank: Anthracite	Bituminous	Subbituminous	Lignite	Total	% of Grand Total
Eastern U.S.						
Deep	7.17	161.51	-	-	168.68	38.72
Surface	0.09	32.51	-	-	32.60	7.48
Total	7.26	194.02	-	-	201.28	46.20
Western U.S.						
Deep	0.13	8.00	123.03	-	131.16	30.10
Surface	-	31.00	45.24	27.00	103.24	23.70
Total	0.13	39.00	168.27	27.00	234.40	53.80
United States						
Deep	7.30	169.51	123.03	-	299.84	68.82
Surface	0.09	63.51	45.24	27.00	135.84	31.18
Total	7.39	233.02	168.27	27.00	435.68	100.00
% of Grand Total	1.70	53.48	38.62	6.20	100.00	

Sources: Refs. 6 and 7.

6.2 OVERVIEW OF THE COAL GASIFICATION PROCESS[9]

6.2.1 Generalized Gasification Process

Although there are several processes available and under development for coal gasification, most are based on a few general chemical reactions. The main objective of each process is to add hydrogen (via steam) to the carbon contained in coal, thereby producing methane (CH_4), the major constituent of high-Btu gas. Table 6.2 outlines the major steps required in any high-Btu coal gasification process.

The first step is the gasification of the coal by reaction at high temperature and pressure with oxygen and steam. Although many reactions occur in the gasification vessel, the overall reaction that occurs is

$$C + H_2 \rightarrow CO + H_2.$$

This reaction is highly endothermic (heat-absorbing). The most common way to provide the necessary heat is to react oxygen with coal char formed in the gasifier. This reaction is

$$C + 1/2\ O_2 \rightarrow CO + \text{heat}.$$

Other reactions that take place in the gasifier result in the formation of carbon dioxide, hydrogen sulfide, and ammonia. The devolatilization of the coal entering the gasifier produces small amounts of methane, tar oil, phenol, naphtha, and other constituents. The gas stream leaving the gasifier will also contain coal dust, ash, and char.[10]

Gas leaving the gasification phase has a heating value of approximately 250-450 Btu/scf. Additional steps are required in the process to remove CO_2, H_2S, and other impurities and to increase the heating value by methanation.

As shown in Table 6.2, the next step is shift conversion of the synthesis gas. During this step, the gas is catalytically reacted with steam to convert the carbon monoxide into carbon dioxide and hydrogen. The reaction is

$$CO + H_2O \rightarrow CO_2 + H_2.$$

The objective of the shift conversion is to bring the mole ratio of hydrogen to carbon monoxide to a value of at least three to one to create favorable conditions for methanation.

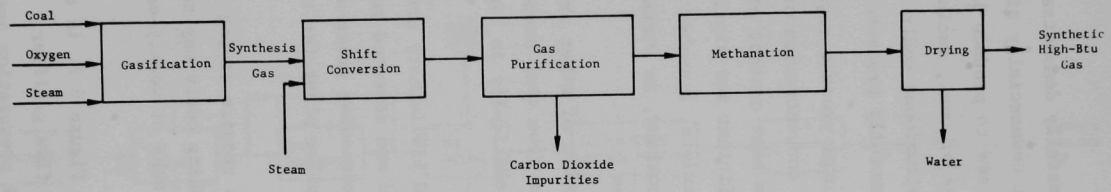
The next step in the coal gasification process is gas purification. This is generally done by gas scrubbing to remove the CO_2. Hydrogen sulfide, H_2S, which would deactivate the catalyst used in the next process step, is also removed along with other gas impurities.

Following purification, the gas is methanated by reacting carbon monoxide and hydrogen. This is a key step because it increases the heating value of the synthesis gas from around 250-450 to 900-1000 Btu/scf. The reaction is

$$CO + 3\ H_2 \rightarrow CH_4 + H_2O.$$

Methanation requires a catalyst that is generally made from nickel. The reaction produces a considerable amount of heat, and care must be taken to prevent overheating the catalyst. This precaution is generally observed by recycling the product gas to reduce the total carbon monoxide concentration in the feed gas.

Table 6.2. High-Btu Gasification Process



Unit Operation	Gasification	Shift Conversion	Gas Purification	Methanation	Drying
Reaction	$C+H_2O \longrightarrow CO+H_2$	$CO+H_2O \longrightarrow CO_2+H_2$	CO_2 and Impurities Removed	$CO+3H_2 \longrightarrow CH_4+H_2O$	H_2O Removed
Major Gas Constituents	CO H_2 CO_2 CH_4 H_2O Impurities	CO (decreased) H_2 (increased) CO_2 (increased) CH_4 H_2O Impurities	$3H_2$, CO } 3:1 Min. Ratio CH_4	CH_4 H_2O	CH_4

6.2.2 *The Lurgi Process*[11,12,13]

The Lurgi gasification process was successfully demonstrated in the pilot plant scale in 1930 and has been available commercially since 1936. To date, sixteen plants have used the Lurgi process to produce low-Btu gas (synthesis gas, town gas). Reportedly, 59 grades of coal, including coke, anthracite, semi-anthracite, bituminous and subbituminous coals (including caking coals), lignite, and peat have been successfully processed.[14]

The production of high-Btu gas from the Lurgi process requires an added methanation process step to increase the methane concentration of the raw Lurgi gas. Methanation results in increasing the heat content of the gas from about 430 to about 970 Btu/cf, which is sufficient for pipeline use. Although no commercial-scale, high-Btu facility exists, a number of methanation pilot plants and a demonstration plant in Scotland, as stated, have produced high-Btu gas from the Lurgi synthesis gas.

Besides gasification and methanation, a number of other processes are required to produce high-Btu, pipeline quality gas from coal commercially by the Lurgi process. These processes are shown schematically in Figure 6.1 and described below.

Coal Treatment. After mining, washing, and preliminary crushing, the feed coal for the Lurgi process is further crushed and screened to approximately 2 x 1/8 inches. During the crushing and screening process the coal fines are collected and routed to the auxiliary boiler plant for the production of steam and electric power.

Coals with a high moisture content may also require drying to about 25% moisture before being fed to the gasifier. Caking coals may require heating to partially devolatilize and render them non- or weakly-caking prior to input to the vessel.

Gasification. The Lurgi gasifier, shown in Figure 6.2, is a water-jacketed, pressurized, moving-bed, counter-current flow gasifier. After crushing and sizing, coal is conveyed from the coal preparation area to a lock hopper directly above the gasifier vessel. The coal enters the depressurized hopper through a hydraulically operated valve. A small quantity of gas may escape during the operation of the hopper and is exhausted together with excess air to be incinerated and vented, or it is added to the raw gas exit

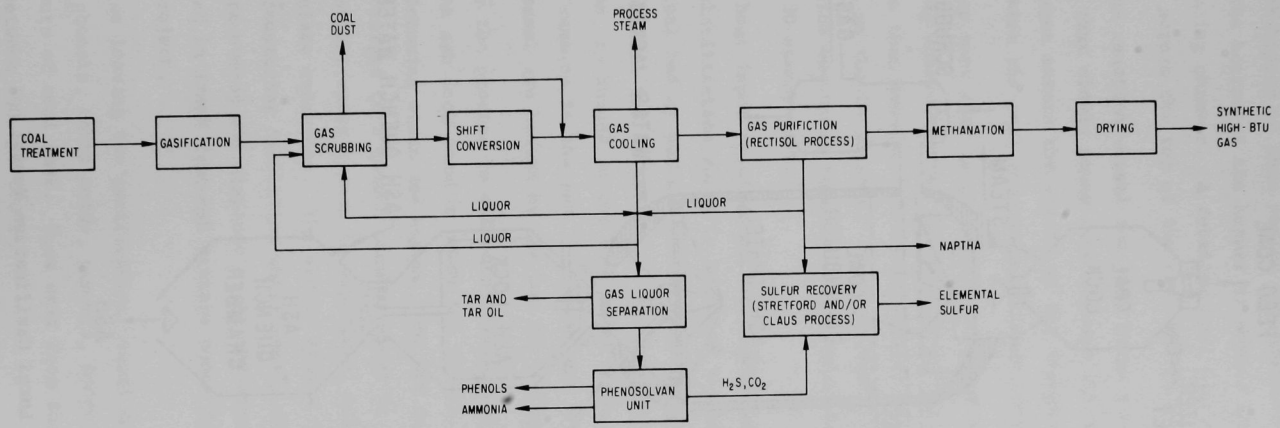


Fig. 6.1. Lurgi Coal Gasification Process

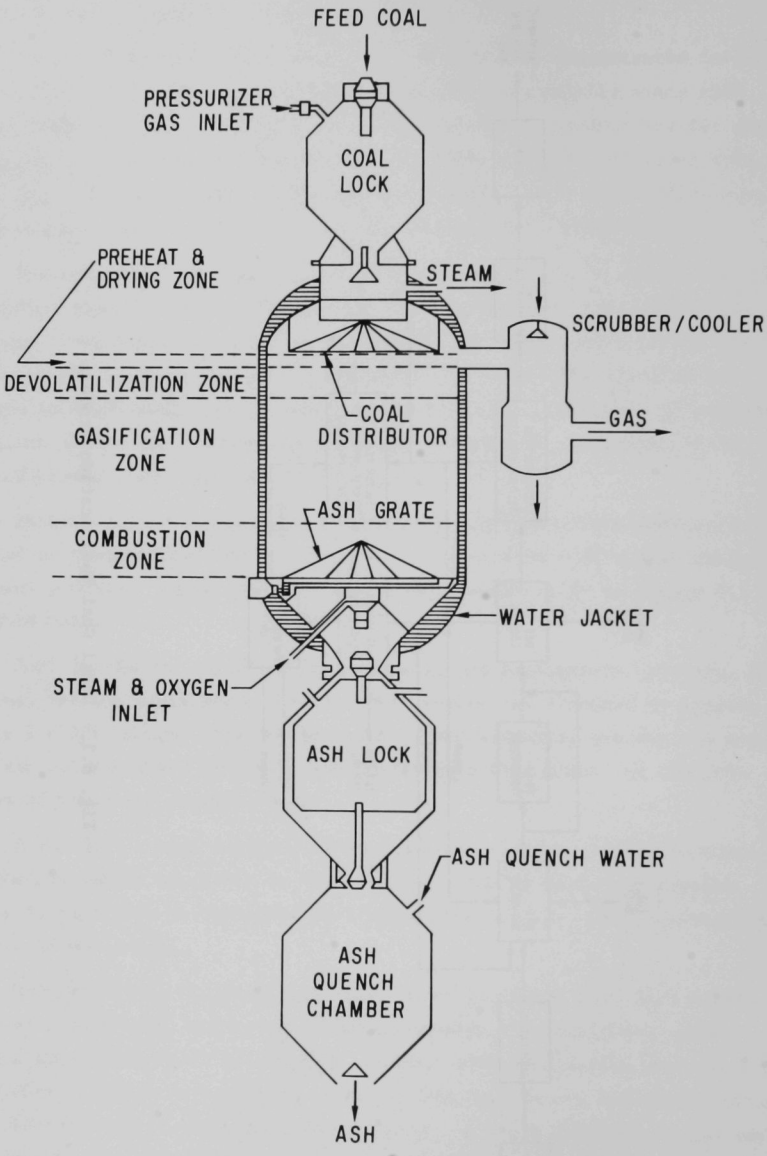


Fig. 6.2. Lurgi Gasification Vessel

stream. The lock hopper is then sealed and pressurized, with crude gas leaving the gasifier. The bottom of the hopper is opened and the coal is transferred to the gas producing chamber. A rotating coal distributor automatically feeds the coal evenly across the top of the coal bed in the gasifier vessel.

Within the reaction vessel the coal forms a bed, comprising four distinct zones, that slowly moves down through the vessel chamber. A mixture of steam and oxygen enters the vessel at the bottom and moving upward through the bed reacts with the coal and exits as crude synthesis gas.

In the top zone coal is preheated and dried by contact with the hot crude gas flowing upward leaving the reactor vessel. After the coal is heated and dried, it is then devolatilized (carbonized) in the second zone followed by gasification in the third zone. There is some overlap in the second and third zones, which encompass temperatures ranging from 1150 to 1600°F at pressures between 20 and 30 atmospheres.[15]

The net heat input required by the chemical reactions in the gasification and devolatilization zones is produced in the combustion zone at the bottom of the coal bed by partial or complete combustion of residual carbon. About 85% of the coal fed to the vessel is gasified. The remaining 15%, which is mainly carbon, is burned in the combustion zone. A small amount (∿0.75%) of unreacted coal remains in the ash.[16] Oxygen and steam entering the bottom of the gasifier vessel are heated by the hot ash moving down from the reactor.

Ash from the process is collected continously by a rotating ash grate and moved to the ash lock chamber below the vessel. After being partially cooled by the incoming steam and oxygen, the ash is collected in the lock hopper and discharged to a quench chamber where it is quenched with water. About a third of the water quench is vaporized, collected, and scrubbed to control particulate emissions. The sluice system collects the ash and moves it to the ash dewatering facilities where nearly all (>90%) but the very fine particles are recovered and disposed of in the mine. The finer particles are generally stored in lined fine-ash storage ponds for the duration of the gasification project.

Crude gas leaving the gasification vessel contains steam, tar, tar oil, naphtha, phenols, fatty acids, ammonia, hydrogen, sulfide, sulfur compounds and small amounts of coal dust. Upon exit from the gasifier stream, gases have temperatures between 600 and 800°F.

Cooling of the gasifier vessel is accomplished by passing steam through the water jacket surrounding the vessel.

Gas Scrubber-Cooler. Adjacent to the gasifier vessel is the gas scrubber-cooler. Raw gas exiting the gasifier vessel enters this chamber where it is cooled rapidly and where the dust is scrubbed out by quenching with a gas liquor spray. Gas liquor used in this process is provided by the condensation derived from the gas cooling process.

Shift Conversion. The shift conversion unit is a series of two catalytic reactors that convert carbon monoxide and water to hydrogen and carbon dioxide. Only a portion of the raw gas is subjected to the shift conversion process, the balance being sent directly to the gas cooling step. The ratio of these two streams is adjusted to achieve the hydrogen to carbon monoxide ratio required to optimize the methanation process. Generally, about half of the raw gas undergoes shift conversion.

The crude gas entering this process has been cooled in the previous step to condense out some of the heavy hydrocarbons. The gas stream is reheated using the hot exit gases from the shift reactors. The reheated gas is then processed through the first reactor where most of the carbon monoxide and steam is converted to carbon dioxide and hydrogen. The second reactor further converts carbon monoxide to carbon dioxide.

Gas Cooling. The gas cooling step cools hot gases from the gasification and shift conversion steps to about 375°F before it enters the low temperature gas purification process. The gas is cooled by two sets of heat exchangers; one set cools the crude gas that bypasses shift conversion and the other cools the converted gas. Cooling of both streams is similar -- the gas is first cooled in waste heat boilers for low or medium pressure process steam generation and is cooled further by air or water, or both. As the gas is cooled, the condensates (hot gas liquors and tar formed mainly during steam generation) are removed. Some of the liquor is recycled to the scrubber-cooler, after which it is recombined with the gas cooling effluent stream, and the total is then transferred to the gas liquor separation step.

Next the stream of converted gas is compressed and mixed with the crude gas stream. The recombined stream has an optimum ratio of hydrogen to carbon monoxide, which is about 3.5 to 1.[17]

Gas Purification (Rectisol Process). The Rectisol process is a proprietary Lurgi purification process used for the removal of carbon dioxide, hydrogen sulfide, and other impurities from the recombined and cooled gas by washing with methanol at low temperatures. The gas is chilled further before entering the pre-wash tower, where water and naphtha are removed by a cold methanol wash. Naphtha is recovered from methanol and water by means of a naphtha extractor, and the methanol is recovered by distillation in a methanol-water distillation column.

The naphtha-free gas then enters the hydrogen sulfide absorber where carbon dioxide, hydrogen sulfide, and other sulfides are removed by a cold methanol wash to a level of 0.1 ppm by volume of total sulfur. Some of the dissolved acid gases are removed from the methanol in a series of multistage pressure reductions. Remaining acid gases are stripped in a hot regenerator, and acid gas streams are routed to the sulfur recovery units.

Sulfur-free gas exits the Rectisol unit and flows to the methanation area. After methanation and first stage product gas compression, the gas returns to the Rectisol unit, where it is chilled, and enters the final carbon dioxide absorber. The carbon dioxide content of the gas is reduced to product specification by the cold methanol wash, and the product gas is sent to the second stage compression unit.

Methanation. Gas from the purification step is reheated to about 500°F before methanation. The methanation process converts the low-Btu synthesis gas from the Rectisol step to high-Btu gas by catalytically combining the carbon monoxide and carbon dioxide with hydrogen to form methane and water by

$$CO + 3H_2 \rightarrow CH_4 + H_2O + \text{heat},$$

and

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O + \text{heat}.$$

A nickel catalyst is used in fixed-bed methanator units.

Other minor reactions take place including the hydrogenation of ethylene to ethane, and hydrocracking of ethane to methane. The methane content of the gas is increased during this step from 10-15% to about 93% with the heating value increasing from about 430 to about 950 Btu/scf.[18]

Heat that is liberated in the methanation reactions is utilized to generate process steam for use in the gasifiers.

Compression and Dehydration. The exit stream from the methanation process is compressed from about 280 to 1000 psig required for transmission. The stream is air and/or water cooled and processed through a final Rectisol unit prior to metering and sendout. Final drying of the product gas is accomplished through the second stage Rectisol unit. The final Rectisol process may also reduce the CO_2 concentration from about 2% to less than 0.5% by volume, increasing the gas heating value about 20 Btu/scf.[19]

Gas Liquor Separation. Gas liquor recovered from the gas cooling and gas purification areas contains tars, tar oils, and dissolved compounds such as phenols, ammonia, carbon dioxide, and hydrogen sulfide. The gas liquor separation unit takes the incoming stream at a high pressure and depressurizes it to atmospheric pressure. This process removes some of the dissolved gases and allows heavier tars and tar oils to settle out. The remaining clarified aqueous liquor stream is further processed in the phenosolvan unit.

Phenol Recovery. The clarified aqueous liquor stream from the gas liquor separation unit is passed countercurrently to isopropyl ether solvent in extractors to remove phenols. The solvent is recovered and the phenol transferred to storage for subsequent sale.

The dephenolized aqueous liquor is then neutralized to remove hydrogen sulfide and carbon dioxide and the resulting water is distilled to recover aqueous ammonia, which is further processed to produce salable ammonia. The remaining water is used as cooling water makeup.

The hydrogen sulfide and carbon dioxide are vented to the sulfur recovery process.

Sulfur Recovery. The lean acid gas stream from the Rectisol unit is processed through the Stretford sulfur recovery process to remove the hydrogen sulfide and recover it as elemental sulfur. The Stretford process operates in a continuous regenerative fashion using a dilute aqueous solution containing sodium carbonate, sodium bicarbonate, sodium metavanadate, and anthraquinone disulfonic acid (ADA) -- a catalyst.

Hydrogen sulfide in the entering gas stream is absorbed by the alkaline carbonate solution countercurrently in a grid-packed tower forming hydrogen sulfide ions. The sulfide is then oxidized to free sulfur.

Since the effluent gas stream also contains a high concentration of carbon dioxide, the regenerated liquor is air stripped to remove carbon dioxide before returning it to the absorber. The stripped carbon dioxide air stream is essentially free of hydrogen sulfide and is vented directly to the atmosphere.

The effluent gas stream, after removal of hydrogen sulfide, is incinerated along with other sulfur compounds, such as carbonyl sulfide (COS) and carbon disulfide (CS_2).

The stream from the Rectisol unit, containing hydrogen sulfide, and the stream from the regenerative SO_2 recovery unit are mixed and directed to a Claus sulfur recovery unit, where the two gases react to form sulfur. The sulfur is condensed and separated as a liquid from the gas.

6.3 NORTH DAKOTA REFERENCE SYSTEM

The system for gasifying North Dakota lignite was defined from information on gasification of this coal and western subbituminous coals.[20-25] In general, the design parameters from the different sources agreed. Where possible, the reference system parallels the system of the American Natural Gas Company (ANG) project proposed for Mercer County, North Dakota.[20]

6.3.1 Capacity and Operating Factors

The North Dakota lignite (NDL) gasification system is assumed to be baseloaded and thus unable to meet major daily or seasonal fluctuations in load. The maximum sendout capacity is assumed to be 292 MMcfd of gas, with an annual operating factor of 85.5%, resulting in an average daily sendout of 250 MMcfd. The Lurgi gasification process with methanation is used.

The number of Lurgi gasification vessels required to service a typical 250 MMcfd sendout facility can be estimated from the designs proposed by El Paso, WESCO, and Panhandle Eastern Gas Companies. The number of vessels in service for each of these facilities is 24, 27, and 29, respectively, with either 3 or 4 standby gasifier vessels.[26] The NDL system is assumed to have 29 service vessels with 3 standbys to be used while maintenance is being performed on the others.

The quality of the send-out gas is assumed to be comparable to that expected by American Natural Gas Company's North Dakota system -- a methane concentration of 95.95 vol. % and a heating value of 970 Btu/cf. Other components of the crude and product gas streams are summarized in Table 6.3. The send-out pressure is assumed to be 1000 psig, which is compatible with that of typical gas transmission systems.

Table 6.3. Crude and Product Gas Specifications (Percent by Volume unless Otherwise Noted)

Component	Formula	Crude Gas[a,b]	Product Gas[c,d]
Methane	CH_4	10.3	95.95
Hydrogen	H_2	39.0	2.00
Carbon Monoxide	CO	20.0	0.05
Carbon Dioxide	CO_2	28.7	0.40
Nitrogen & Argon	N_2 & Ar	0.6	0.60
Hydrogen Sulfide	H_2S	0.4	0.25 grains/100 cf[e]
Total Sulfur	S	-	<10 grains/100 cf
Ethane	C_2H_6	0.6	0.6
Ethylene	C_2H_4	0.4	0.4
Specific Gravity		0.75	0.60
Heating Value		250-450 Btu/cf	970 Btu/cf

[a]Sargent and Lundy Engineers, *Technology Characterization Lurgi Coal Gasification Process for Production of High-Btu Synthetic Natural Gas*, Exhibit 8, based on data for El Paso and WESCO coal gasification projects.

[b]Baria, D.N., *Evaluation of Gasification and Liquefaction Processes using North Dakota Lignite*, p. 10.

[c]American Natural Gas Company, *FEIS for North Dakota Gasification Project*.

[d]Strakey, J.P. et al., *Methanation in Coal Gasification Processes*, Second Annual Symposium on Coal Gasification, Liquefaction, and Utilization, University of Pittsburgh, Pa. (Aug. 5-7, 1975).

[e]Less than 5×10^{-6}%.

6.3.2 *Coal Requirements*

Feed coal requirements for various proposals normalized to the production of 250 MMcfd of synthetic natural gas are listed in Table 6.4. The throughput of coal in the Lurgi gasifier is about 3500 tons/day greater for lignite than for subbituminous coals. From the information in Table 6.4, 26,000 tons/day of North Dakota lignite is assumed necessary to produce an average of 250 MMcfd of gas. A maximum output of 292 MMcfd would require processing of about 30,370 tons/day.

The quality of coal as received at the gasification facility is assumed to be identical to that expected by the American Natural Gas Company in Mercer County and is typical of lignites found in the Mercer/Dunn County area of North Dakota. An analysis of coal as received from the mine is shown in Table 6.5.

Table 6.4. Coal Requirements for 250 MMcfd Gasification Processes

Project/Reference	Coal Rank	Requirement (tons/day)
El Paso/Ref. 21	Subbituminous	20,182
Panhandle/Ref. 21	Subbituminous	21,046
WESCO/Ref. 21	Subbituminous	25,100
Am. Nat. Gas/Ref. 20	Lignite	26,000
Fletcher, A.G./Ref. 23	Lignite	26,627
Baria, D.N./Ref. 24	Lignite	24,230
NDL Reference System	Lignite	26,000

Table 6.5. Analysis of North Dakota Lignite (as received)

Component	Weight %
Moisture	35.98
Ash	7.42
Fixed Carbon	29.39
Volatile Matter	27.21
	100.00
Heating Value	6820 Btu/lb
Sulfur Content	1.6%

Sources: Woodwand-Clyde Consultants, *Environmental Impact Report North Dakota Gasification Project for ANG Coal Gasification Co.*, pp. 1-42, 1-60, 3-128. Keystone Coal Industry Manual.

6.3.3 Requirements for Oxygen and Process Steam

Gasification of coal requires that significant quantities of oxygen and steam be passed countercurrently through the gasification vessel to react with the coal. The estimated volumes of oxygen and steam required to gasify North Dakota lignite are 4.93 ft^3 oxygen per pound of moisture and ash free (MAF) coal, and 6.5 moles of steam per mole of oxygen.[27] For the reference system, these values convert to 5947 tons/day of oxygen and 21,743 tons/day of process steam at the average production rate of 250 MMcfd of synthetic gas.

Oxygen is supplied to the gasification vessels by a cryogenic air-separation plant, which fractionates about 25,860 tons of air per day. The process steam is supplied by the main boilers and waste heat recovery boilers. Waste heat recovery boilers supply enough energy for about 25% of the required process reaction steam; the remainder is generated by the burning of 3700 tons/day of coal in the main boilers. Both oxygen and steam are introduced into the vessel at about 500 psig and 750°F.[28]

6.3.4 Auxiliary Power Requirements

Auxiliary power for final consumption in the gasification plant is required in two forms: electrical energy and high-pressure steam to drive large compressors and pumps. Available information[29-31] indicates that an estimated 55 MW of electricity is required for operation of a gasification plant producing 250 MMcfd. Related coal mining requires an additional 22 MW[32-34] to give a total electrical energy requirement of 77 MW. Mine generation is based on a 7 day per week -- 18 hours per day -- mining operation, while plant electricity generation is continous. The necessary electrical energy is generated onsite at a 33% conversion efficiency, thus an average of 1305 tons of lignite per plant operating day is used.

Requirements for auxiliary steam not used for generating electrical power or in gasification are estimated to be about 900,000 lb/hr at 1200 psig and 925°F.[35,36] Although in some current designs part of the salable by-products is used for production of this steam, the reference system is assumed to use only coal fines and vent gases of negligible heating value for this purpose. At a conversion efficiency of 85%, a total of 2535 tons/day of coal fines is consumed in the main boilers and superheaters. Table 6.6 summarizes coal requirements for gasifier feed, process steam, and auxiliary energy requirements.

Table 6.6. NDL Reference System Coal Requirements

Use	Consumption (tons/day)
Gasifier feed	26,000
Process Steam	3,700
Electricity generation (mine and plant)	1,305
Other auxiliary steam	2,535
Total	33,540

6.3.5 Miscellaneous Material Requirements and By-products

Miscellaneous materials required include those needed for treatment of water and flue gas as well as catalysts consumed in the shift conversion and methanation process and in the sulfur plant. Table 6.7 lists representative annual quantities consumed in the production of 250 MMcfd of synthetic gas. Several by-products are produced in converting coal to synthetic natural gas. The reference system is assumed to produce the products at a rate equal to that expected in the ANG North Dakota proposal. Some of these products could be used as boiler or superheater fuels. In the ANG design, for example, all of its produced tar would be used as boiler fuel (about 512×10^6 Btu/hr).[37] In the reference system, however, no inplant use of by-products is assumed. Table 6.8 summarizes these by-products.

6.3.6 Water Requirements

A water balance has been derived for the NDL reference coal gasification system from an analysis of several proposed designs for the western states. Table 6.9 summarizes this balance.

Two items in the water balance can vary significantly: water losses due to evaporation and drift; and the consumptive uses for the coal mines. Evaporation and drift are determined primarily by tradeoffs between availability of make-up water and the cost of providing significant air cooling. Where the water supply is at a minimum, additional capital will be needed for air cooling equipment and more sophisticated methods to eliminate cooling tower drift. Values of evaporation and drift are expected to be 4000-8000 gpm. Mine use generally depends on the amount of water in aquifiers encountered during mining. Any aquifiers containing large amounts of water may supply a

Table 6.7. Requirements for Miscellaneous Material

Material	Process Unit	Consumed/yr (250 MMcfd Plant)
Methanol	Rectisol	-
Isopropyl Ether	Phenosolvan	1,160 tons
Sulfuric Acid	Water Treating	11,160 tons
Caustic Soda	Water Treating	20,160 tons
Lime	Water Treating	3,000 tons
Limestone	Stack & Tail Gas Treat.	40,220 tons
Desiccant	Oxygen Plant	30 tons
Bauxite	Sulfur Plant	45 tons
Catalyst	Sulfur Plant	312 ft^3
Catalyst	Shift Conversion	17,160 ft^3
Catalyst	Methanation	Regenerated

Source: Sargent and Lundy Engineers, *Technology Characterization Lurgi Coal Gasification Process for Production of High-Btu Synthetic Natural Gas*, SL-3276, Exhibit 27.

Table 6.8. NDL Reference System By-products Production

By-product	Production	
	Tons/day	Gal/day
Naphtha	158.2	46,241
Tar Oil	533.6	137,566
Tar	373.4	83,672
Crude Phenols	123.1	28,112
Anhydrous Ammonia[a]	230.2	89,014
Sulfur[b]	508.0	-
Sodium Sulfate[c]	20.8	-

Source: ANG Coal Gasification Plant Environmental Report,(Ref. 12, p. 1-75).

[a]Ammonia is extracted from phenol-water stream after phenols are removed in the Phenosolvan. (ANG p. 1-49). Ammonia production for El Paso, WESCO, and ANG projects ranges from 1.78-1.94 tons/ton of phenol. The average of 1.87 tons (NH_5)/ton phenol was used.

[b]Based on sulfur content of feed coal and recovery assumptions stated in Section 6.5.1.

[c]Excess sodium sulfate ($Na_2 SO_4$) generated in regenerative sulfur absorption unit due to presence of oxygen in flue gas which causes oxidation of sulfite to sulfate. (ANG p. 1-62). Purged sodium sulfate for reference system based on ANG data adjusted for volume of coal fired in reference system.

Table 6.9. Water Balance for NDL Reference System (gpm)

Water Inputs:	
Makeup from Natural Sources	10,500
Gasifier and Boiler Coal	900
Other Process Sources	600
Total	12,000
Water Losses:	
Evaporation and Drift	8,000
Leaks and Vents	500
Reactants and By-products	2,000
Ash Disposal	200
Consumptive Mine Uses	1,300
Total	12,000

Based on references 20, 22, 23, 24.

significant amount of the needed water. However, aquifier encounter can increase the cost of coal extraction, disrupt or change the direction of the aquifier flow, and potentially affect other users of the ground water.

6.3.7 Land Requirements

From requirements for several proposed projects, about 1500-2000 acres was estimated for the total site (excluding the area needed for mining). Of this total, about 650-700 acres will be occupied by buildings, process equipment, and coal storage.[38] Estimated coal storage area is about 39 acres.

Land area disrupted by the mining depends on the annual production and the coal-seam thickness. *In-situ* coal has an average density of about 1750 tons per acre-foot. With an assumed seam thickness of 20 ft for the reference system, mining of the required 33,540 tons/day (12.2 million tons/year) of lignite would disturb about 350 acres annually.

The total unreclaimed land present at any one time varies from about 350 to 1200 acres. These values correspond to about one to three years of mining disruption. For the reference system, land equivalent to two years of mining is assumed to be the maximum unreclaimed at any one time.

6.3.8 Employment

Estimated annual employment for construction of the NDL reference gasification plant and mine are shown in Table 6.10. Although employment requirements may vary depending on the exact construction schedule, these figures are representative of several coal gasification projects planned for the western states.

Over a 7-year period, a total 6970 man-years of effort would be expended, all but 20 of these during the final 5-year construction period. Generally, the first two years require only a small number of personnel for surveying and field services.

Estimates of operational employment for a 250 MMcfd plant range from about 615 to 890 with supporting mine activities employing between 290 and 400 persons.[39] The NDL reference plant is assumed to employ a total operational force of 1125 persons. Of these, 750 are employed in the plant and 375 in supporting mine activities. Supervisory mine personnel total 40 persons, and 335 persons are engaged in actual mining operations. The mine operates 7 days per week for 18 hours each day, and miner productivity is about 100 tons/man-day.[40]

6.3.9 Construction and Operating Costs

Construction costs. Construction costs for the NDL reference gasification plant are based on data obtained from Panhandle Eastern Pipeline Company and reflect current estimates of costs to construct a proposed gasification facility in eastern Wyoming.[41] These data correlate well with other recently published coal gasification plant capital cost estimates. Total direct costs are estimated at $878.8 million (1975). Preoperational, start-up, working capital, and other indirect costs add an additional $120.2 million. Interest during construction, calculated at a constant dollar rate of 3% per year is $77.0 million, for a total plant capital investment in constant dollars of $1076.0 million. These costs are included in Table 6.10.

Construction costs for a 12.2 million ton per year supporting mine were estimated from data available from the Bureau of Mines.[42] These data indicate that a mine of this capacity in the Northern Great Plains region would have a direct construction cost of $37.4 million (1975). Indirect

costs add $11.2 million and interest during construction is $3.8 million for a mine construction cost of $52.4 million.

By the Bureau's estimates 35% of the mine's physical equipment, worth $13.0 million, depreciates in an average of 6.7 years and thus requires replacement twice throughout the 20-year lifetime of the mine. The present value of the replacement costs based on a 17% current dollar cost of capital and a 6% inflation rate is $10.3 million. Thus, the total capital investment for a supporting mine is $62.7 million. Mine capital costs are also shown in Table 6.10.

Operating Costs. The 1975 operating costs, in 1975 dollars, for a 250 MMcfd gasification plant are estimated at $52.0 million per year.[43] Components of this total include wages, materials and supplies, taxes other than income taxes, insurance, and other miscellaneous expenses.

The 1975 operating costs for a supporting mine, including such items as wages, operating supplies, union welfare, reclamation, local taxes and insurance, are estimated to total $26.7 million annually.[44] Royalties paid to property owners are estimated at $0.35 per ton of coal, or $4.3 million annually. Operating costs and royalties are estimated to escalate at 1.5% above an inflation rate of 6%.

Table 6.10. Annual Construction Employment for NDL Reference System

Year	1	2	3	4	5	6	7
Mine Employment	8	12	35	80	135	75	25
Plant Employment	-	-	335	1315	2140	2175	615
Total Employment	8	12	390	1395	2275	2250	640

Adapted from: 1) Woodward-Clyde Consultants, *Environmental Impact Report North Dakota Gasification Project for ANG Coal Gasification Company,* (Ref. 12), p. 1-29.
2) U.S. ERDA and U.S. DOI, *Synthetic Fuels Commercialization Program DEIS,* (Ref. 25), p. IV-45.
3) Sargent and Lundy Engineers, *Technology Characterization Lurgi Coal Gasification Process for Production of High-Btu Synthetic Natural Gas,* (Ref. 9), Exhibits 37 & 38.

Table 6.11 shows the 20-year levelized annual operating costs for plant and mining operations.

Table 6.11. NDL Reference System Costs

Component	Cost ($10^6$1975$)
250 MMcfd Gasification Plant	
Direct Capital	878.8
Indirect Capital	120.2
Total Capital Cost	999.0
Interest During Construction (@ 3%)	77.0
Total Plant Investment	1076.0
Levelized Annual Operating and Maintenance Cost	66.6
12.2 Million Ton Per Year Surface Mine	
Direct Capital	37.4
Indirect Capital	11.2
Total Capital Cost	48.6
Interest During Construction (@ 3%)	3.8
Total Construction Cost	52.4
Present Value of Future Requirements	10.3
Total Mine Investment	62.7
Levelized Annual Operating and Maintenance Cost	34.2
Levelized Annual Royalties	5.5
Total Annual Charges	39.7

Based on References 41, 42, 43, 44.

Required Income and Prices. It has been assumed, based on current interests, that coal gasification operations in the 1985-1990 time frame would be owned and operated by gas transmission companies. These companies typically have debt-equity ratios of 60:40%, bond rates of 9%, returns on equity of 15%, and a federal income tax rate of 48%.

Estimating an inflation rate of 6%, the after-tax constant dollar cost of capital is 10%. An annual capital charge rate of 12% results for the 20-year service life of the NDL reference system mine and plant. Applying this rate to the plant and mine investments and adding the levelized operation and maintenance costs results in a 1975 constant dollar revenue requirement of $242.97 million. Sale price of the product gas (970 Btu/cf) would thus be $2.66/Mcf or $2.74/MMBtu.

6.3.10 *Summary of Reference System Parameters*

Significant parameters associated with gasification in the North Dakota lignite reference system are summarized in Table 6.12. Environmental residuals associated with this system are discussed in Section 6.5.

Table 6.12. Summary of 250 MMcfd NDL Reference Gasification System Characteristics

Maximum Daily Sendout, MMcfd	292
Operating Factor, %	85.5
Average Daily Sendout, MMcfd	250
Heating Value, Btu/cf	970
Number of Service Gasifiers	29
Number of Standby Gasifiers	3
Oxygen Plant Production Rate, tons/day	5947
Process Reaction Steam at 500 psig and 750°F, tons/day	21,743
Lignite Feed to Gasifiers (avg), tons/day	26,000
Lignite Feed to Aux. Boilers (avg), tons/day	7540
Coal Composition, wt %	
Moisture	35.98
Ash	7.42
Fixed Carbon	29.39
Volatile Matter	27.21
Total	100.00
Heating Value, Btu/lb	6820
Sulfur, wt %	1.6
Electrical Capacity, MW	
Gasification Plant	55
Mine	22
Total	77
By-products Produced, tons/day	1947
Water Consumed, gpm	12,000
Land Requirements	
Total Gasification Site, ac	1500-2000
Facilities, ac	650- 700
Coal Mining, ac/yr	350
Land Unreclaimed at one time, ac	700
Project Construction Period (excluding 24 months of site survey), months	60

Table 6.12. (Cont'd)

Construction Manpower, Man-years	
Mine	370
Plant	6600
Total	6970
Peak Construction Force	2275
Operational Work Force	
Plant	750
Mine	375
Total	1125
Costs, Million 1975 dollars	
Plant Direct Construction	$ 878.8
Plant Indirect Construction	120.2
Interest During Construction (@ 3%)	77.0
Total Plant	$1076.0
Levelized Annual Plant Operation and Maintenance	$ 66.6
Mine Direct Construction	$ 37.4
Mine Indirect Construction	11.2
Interest During Construction (@ 3%)	3.8
Present Value of Future Replacements	10.3
Total Mine	$ 62.7
Levelized Annual Mine Operation, Maintenance and Royalties	$ 39.7
Plant Component of Energy Cost, $/Mcf	$ 2.14
Mine Component of Energy Cost, $/Mcf	.52
Total	$ 2.66
Energy Cost, $/MMBtu	$ 2.74

6.4 SOUTHERN ILLINOIS BITUMINOUS (SIB) REFERENCE SYSTEM

Because little information directly concerned with the gasification of Illinois coals in commercial-scale Lurgi gasifiers is available, approximations for coal gasification in Southern Illinois were made from information available on projects planned for the western United States. This information was adapted by using data in the Synthetic Fuels Commercialization Program Environmental Statement (SFCPES) and the results of tests on the gasification of various U.S. coals in a Westfield, Scotland, Lurgi gasifier.[45,46]

6.4.1 *Capacity and Operating Factors*

The reference system, assumed to be in Fulton County, Illinois, uses Illinois No. 6 bituminous coal as gasification feed and for auxiliary purposes. The system is assumed to be baseloaded, with a maximum sendout capacity of 292 MMcfd and an annual operating factor of 85.5%. The average daily sendout is 250 MMcfd.

Crude gas leaving the gasifier vessels would have a slightly different makeup than its NDL system counterpart. The primary difference would be in its hydrogen sulfide concentration estimated as three times greater. The approximate composition of the crude gas stream is presented in Table 6.13. Product gas specifications are assumed to be identical to those of the NDL system shown in Table 6.3.

6.4.2 *Coal Requirements*

Data compiled from tests on the gasification of U.S. coals in Westfield, Scotland, indicate that 23.64% less coal on an as received basis, and 6.63% less coal on an MAF basis is required to produce equivalent amounts of crude gas using Illinois coals as compared with Montana subbituminous coal. Although subbituminous and lignite properties differ significantly, the Westfield tests showed strong similarities among their gasification properties. Thus, it is assumed that 8% less MAF coal is required in the SIB gasifiers than is required in the NDL system. Since volatile matter and carbon compose 56.6% of the lignite coal and Illinois No. 6 bituminous contains 80.3%, 16,860 tons/day of bituminous coal is required as gasifier feed stock. Table 6.14 summarizes a typical analysis of Illinois bituminous coal.

A throughput of 850 tons/vessel-day is assumed for the SIB system, requiring a total of 20 service vessels; 3 standby vessels are also needed. The somewhat lower throughput per vessel day and the higher ratio of standby vessels to service vessels are assumed to be necessary because of the much stronger agglomerating or caking characteristics of the Illinois coals.

6.4.3 *Requirements for Oxygen and Process Steam*

Results of gasification tests in Westfield, Scotland, indicate that 54% more oxygen per pound of MAF coal is required to gasify Illinois bituminous

Table 6.13. Crude Gas Specifications for SIB Reference System

Component	Formula	Volume % (Dry Basis)
Methane	CH_4	9.4
Hydrogen	H_2	39.1
Carbon Monoxide	CO	17.3
Carbon Dioxide	CO_2	31.2
Nitrogen and Argon	N_2 & Ar	0.9
Hydrogen Sulfide	H_2S	1.1
Ethane	C_2H_6	0.6
Ethylene	C_2H_4	0.4

Table 6.14. Analysis of Illinois Bituminous Coal (as received)

Component	Weight %
Moisture	8.62
Ash	11.08
Fixed Carbon	45.30
Volatile Matter	35.00
Heating Value	11,000
Sulfur Content (%)	3.5

Adapted from: Keystone Coal Industry Manual and personal communications.

coal compared with western subbituminous or lignite. Oxygen requirements for the NDL system are 4.93 ft^3 per pound of MAF lignite, thus, 7.59 ft^3 of oxygen per pound of MAF coal is necessary to gasify Illinois No. 6 coal. With a throughput of 16,860 tons of coal per day (13,539 MAF tons/day), 2.05×10^8 ft^3 or 8423 tons of oxygen per day are required.

The Westfield tests also indicate that 9% less steam per pound of oxygen is required to gasify bituminous coals as compared to subbituminous or lignite. Since the lignite system assumed 3.65 lbs steam/lb oxygen, an estimate of 3.3 lb process steam/lb oxygen is required in the SIB reference system. A total of 27,800 tons/day of process steam is needed. As with the NDL system, 25% of the process steam is assumed to be generated in wasteheat recovery boilers. The remaining 75% (or 1.74×10^6 lb/hr) is supplied to the

vessel at 500 psig and 750°F by the main boilers. At an 85% conversion efficiency, the generation of this steam in the main boilers consumes about 2940 tons of coal each day.

6.4.4 Auxiliary Power Requirements

The Illinois bituminous reference system requires a larger electrical energy input than the North Dakota lignite system primarily because of the 42% increase in oxygen that is necessary for the gasification process. It is estimated that an additional 19 megawatts of electrical generating capacity will be needed to satisfy this requirement. Thus, plant electrical requirements total 74 MW compared to 55 MW for the NDL system.

Related coal mining operations are estimated to require an additional 16 MW for a total electrical capacity requirement of 90 MW. Electrical generation consumes 965 tons of coal each day.

Auxiliary steam requirements not utilized for electrical generation or process reaction are estimated to be 935,000 lb/hr at 1200 psig and 925°F. This value is about 4% greater than the NDL system and accounts mainly for the heat input required to raise the additional oxygen to 750°F. Like the NDL system, it is assumed all auxiliary steam is generated utilizing coal fines and vent gases of negligible heating value. At a conversion efficiency of 85%, a total of 1665 tons/day of coal fines is consumed in the main boilers and superheaters to provide this energy.

Table 6.15 summarizes coal requirements for gasifier feed, process steam, and auxiliary energy requirements.

6.4.5 Miscellaneous Material Requirements and Salable By-products

No information is available to accurately estimate requirements for nonfuel miscellaneous materials for the reference Illinois plant. Possible differences due to the gasification of a bituminous coal rather than a lignite, however, are not expected to be significant.

By-product production in the SIB System has been estimated by comparing various production rates in the Westfield tests. Table 6.16 summarizes these estimates.

Table 6.15. Summary of SIB Reference System Coal Requirements

Use	Consumption (tons/day)
Gasifier Feed	16,860
Process Steam	2,940
Electricity Generation (Mine and Plant)	965
Other Auxiliary Steam	1,665
Total	22,430

Table 6.16 SIB Reference System By-products Production[a]

By-product	Tons/day	Gal/day
Naphtha	229.6	67,111
Tar Oil	95.0	24,492
Tar	519.2	116,343
Crude Phenols	129.7	29,619
Anhydrous Ammonia	242.5	93,771
Sulfur	740.3	-
Sodium Sulfate	15.4	-

[a]See footnotes Table 6.8.

6.4.6 *Water Requirements*

Because of the large variations possible for water requirements and the general lack of adequate data necessary to quantify this parameter, it is assumed that the Illinois reference coal gasification system requirements are identical to those for the North Dakota system. (See Table 6.9.)

6.4.7 *Land Requirements*

The land requirements for the SIB System plant are assumed to be the same as those for the NDL system -- 1500 to 2000 acres.

The coal is assumed to be mined from an 8-ft seam at 8.2 million tons/yr. This amount of coal, extracted by area surface mining, would disturb about 585 acres annually.

As in the NDL reference system, it is assumed that a mined area equivalent to no more than two years of mining is unreclaimed at any one time.

6.4.8 *Employment*

Construction schedules and manpower requirements are assumed to be identical to those for the North Dakota system -- a construction schedule of 60 months and a peak labor force of 2275. The construction effort is also assumed to be the same as the NDL system -- 6580 man-years of effort for the gasification plant and 370 for the construction of the supporting mine (see Table 6.10).

The operational work force at the plant is assumed to be 750, identical to the NDL system. The extraction of 22,400 tons of bituminous coal per day requires 300 mine personnel -- 265 miners and 35 supervisors. Miner productivity for the SIB system mine is about 85 tons/man-day.[47]

6.4.9 *Construction and Operating Costs*

Construction Costs. Construction costs for the Illinois reference system plant were derived from the North Dakota system values and itemized cost estimates for the American Natural Gas Co. project in North Dakota.[48] Costs for the Illinois System were estimated by adjusting the NDL system component costs proportionally as the capacity or loading to the two-thirds power.* This relationship is often used to estimate electrical generating plant costs and is thought to be reasonably applicable to large coal gasification projects in the absence of detailed engineering cost estimates.

Direct construction costs in constant 1975 dollars were estimated at $940.6 million for the Illinois reference system plant. Indirect costs, including preoperational start-up costs and working capital, add another $122.2 million. Interest during construction, calculated at the historic constant dollar rate of 3% per year is $82 million. Total capital investment for the SIB gasification plant is thus $1144.8 million, or 6.4% higher than the NDL reference system plant.

$$*\frac{\text{SIB Component Cost}}{\text{NDL Component Cost}} = \left[\frac{\text{SIB Capacity or Loading}}{\text{NDL Capacity or Loading}}\right]^{2/3}$$

Construction costs for the 8.2 million ton per year supporting mine were estimated from data available from the Bureau of Mines.[49] A surface mine of this capacity in the Eastern Interior region is estimated to have a direct capital cost of $65.9 million in constant 1975 dollars. Indirect costs would add another $19.8 million, and interest during construction another $6.6 million for an initial investment of $92.3 million.

As with the NDL mine, 35% of the mine's physical equipment, worth $23.0 million, depreciates in one third of the 20-year mine service life. The present value of these replacement costs based on a 17% current dollar cost of capital and a 6% inflation rate is $18.2 million. Thus, the total capital investment for the supporting mine is $110.5 million. Table 6.17 summarizes both the plant and mine costs.

Operating Costs. Annual 1975 operating costs, in 1975 dollars, for the SIB plant are assumed to be $52.0 million -- similar to the NDL system. Annual mine operating and maintenance costs are based on Bureau of Mines data and have been adjusted to account for differences in number of employees and reclamation area between the reference system mine and the Bureau's model. The SIB mine operating and maintenance costs for 1975 are estimated at $19.5 million per year.

Royalties paid to property owners are estimated at $0.50 per ton of mined coal, or $4.1 million annually in 1975 dollars. All operating and maintenance costs and royalties are estimated to escalate at 1.5% above an inflation rate of 6%. Table 6.17 shows the 20-year levelized annual operating costs for plant and mining operations starting in 1985.

Required Income and Prices. Based on the same assumptions as used for income requirement and price determination for the NDL reference gasification system, the constant 1975 dollar revenue requirement associated with the SIB reference system is $247.49 million. Sale price of the product gas (970 Btu/cf) would then be $2.71/Mcf or $2.79/MMBtu.

6.4.10 Summary of SIB Reference System Parameters

The important design, employment, and cost parameters estimated for the Illinois system are summarized in Table 6.18.

Table 6.17. SIB Reference System Costs

Component	Cost (10^6 1975$)
250 MMcfd Gasification Plant	
Direct Capital	940.6
Indirect Capital	122.2
Total Capital Cost	1062.8
Interest During Construction (@ 3%)	82.0
Total Plant Investment	1144.8
Levelized Annual Operating and Maintenance Cost	66.6
8.4 Million Ton Per Year Surface Mine	
Direct Capital	65.9
Indirect Capital	19.8
Total Capital Cost	85.7
Interest During Construction (@ 3%)	6.6
Total Construction Cost	92.3
Present Value of Future Requirements	18.2
Total Mine Investment	110.5
Levelized Annual Operating and Maintenance Cost	25.0
Levelized Annual Royalties	5.2
Total Annual Charges	30.2

Based on References 41-44.

Table 6.18. Summary of 250 MMcfd SIB Reference Gasification System Characteristics

Maximum Daily Sendout, MMcfd	292
Operating factor, %	85.5
Average Daily Sendout, MMcfd	250
Heating Value, Btu/cf	970
Number of Service Gasifiers	20
Number of Standby Gasifiers	3
Oxygen Plant Production Rate, tons/day	8423
Process Reaction Steam at 500 psig and 750°F, tons/day	27,800
Coal Feed to Gasifiers (avg), tons/day	16,860
Coal Feed to Aux. Boilers (avg), tons/day	5570
Coal Composition, wt %	
Moisture	11.08
Ash	8.62
Fixed Carbon	45.30
Volatile Matter	35.00
Total	100.00

Table 6.18. (Cont'd)

Heating Value, Btu/lb	11,000
Sulfur, wt %	3.5
Electrical Capacity, MW	
Gasification Plant	74
Mine	16
Total	90
By-products produced, tons/day	1972
Water Consumed, gpm	12,000
Land Requirements	
Total Gasification Site, ac	1500-2000
Facilities, ac	600- 650
Coal Mining, ac/year	585
Land Unreclaimed at one time, ac	1170
Project Construction Period (excluding 24 months of site survey), months	60
Construction Manpower, Man-years	
Mine	370
Plant	6600
Total	6970
Peak Construction Work Force	2275
Operational Work Force	
Plant	750
Mine	300
Total	1050
Costs, million 1975 dollars	
Plant Direct Construction	$ 940.6
Plant Indirect Construction	122.2
Interest During Construction (@ 3%)	82.0
Total Plant	$1144.8
Levelized Annual Plant Operating and Maintenance	$ 66.6
Mine Direct Construction	$ 65.9
Mine Indirect Construction	19.8
Interest During Construction (@ 3%)	6.6
Present Value of Future Replacements	18.2
Total Mine	$ 110.5
Levelized Annual Mine Operating, Maintenance, and Royalties	$ 30.2
Plant Component of Energy Cost, $/Mcf	$ 2.23
Mine Component of Energy Cost, $/Mcf	.48
Total, $/Mcf	$ 2.71
Energy Cost, $/MMBtu	$ 2.79

6.5 *RESIDUALS*

6.5.1 *Air*

Major sources of air emissions from coal gasification facilities include auxiliary power and steam generation, fugitive losses from lock hopper operations, leaks from pump seals, joints, and flanges, and operation of mining equipment. Auxiliary operations such as power generation, coal drying and sulfur recovery generate the majority of air residuals.

Estimates of uncontrolled air emissions from combustion of auxiliary coal were calculated from EPA emission factors for general pulverized coal furnaces with heat loadings greater than 100 MMBtu/hr coupled with the specific coal properties and system characteristics assumed for each reference system.[50] In addition, the following assumptions were also applied:

1. Emission control efficiencies are: particulates 99% nitrogen oxide 25%, flue gas desulfurization 85%, sulfur recovery 95%, and all others 0%.[51]

2. All sulfur recovered in flue gas desulfurization as well as sulfur contained in the process feed coal (less that retained in the product gas) is sent to the sulfur recovery plant. There, 95% of the input sulfur is recovered. The remaining 5% is recycled to the flue gas desulfurization stream from which 15% is emitted as SO_2 and 85% is again cycled to the sulfur recovery plant.[52]

3. Crude gas losses due primarily to lock hopper operations are assumed to be 1500 Mcfd for the NDL system and 975 Mcfd for the SIB system. The difference is due to less coal processed through the SIB system. Compositions of the crude gas streams are as given in Tables 6.3 and 6.13, respectively, for the NDL and SIB systems.

4. Losses of product gas from pump seals, joints, flanges, and and other leaks is 50 Mcfd for each system. Composition assumed for both systems is given in Table 6.3. Hydrogen sulfide concentration in the product gas stream is 0.25 grains per 100 cf (0.36 lb/MMcf) and total sulfur is assumed to be 7.5 grains per 100 cf (10.7 lb/MMcf).

5. Ammonia (NH_3) production has been found to be 1.87 tons per ton of crude phenol produced in the gasification process. Atmospheric emissions are 0.02% of the production rate.

6. Operation of mining equipment is estimated to require 4.0 gallons of diesel fuel oil per ton of mined lignite,[53] and 4.5 gallons per ton of mined bituminous coal. The difference is primarily a result of the small average seam thickness assumed in the Illinois mine.

7. Diesel fuel is assumed to have a 0.2% sulfur content. Emission factors reported by El Paso Gas Company, based on information supplied by the EPA for heavy-duty diesel vehicles were used.[54] These are:

Pollutant	Emission Factor ($lb/10^3$ gal)
Particulates	12.4
NOx	372.2
SO_2	27.3
Hydrocarbons	43.2
CO	223.4
Aldehydes	7.5

8. Fugitive coal dust from mining operations, conveyers, and stockpiles has been estimated by Panhandle Eastern Pipeline Company to be 0.02% of the mined coal. This factor is assumed for each of the reference systems.[55]

9. Coal drying is necessary for lignite, but not for bituminous coals. The particulate emission factor for coal drying is 0.01 tons/ton of process coal dried.[56]

Table 6.19 summarizes the annual air residuals estimated for each of the coal gasification reference systems.

6.5.2 Water

Waste water constituents are based on an analysis of effluents from the U.S. Bureau of Mines Synthane Process.[57] Dissolved solids concentrations are based on data provided in the environmental statement for American Natural Gas Company's North Dakota proposal.[58] These concentrations are summarized in Table 6.20.

Table 6.19. Annual Air Emissions for the Coal Gasification Reference Systems (tons/year)

Air Residual	North Dakota Lignite System			Southern Ill. Bituminous System		
	Mine	Plant	Total	Mine	Plant	Total
Particulates	304	2,583	2,887	228	1,802	2,030
NOx	9,113	18,577	27,690	6,856	13,723	20,579
SOx	668	15,478	16,146	503	24,546	25,049
Hydrocarbons	1,058	2,150	3,208	796	1,492	2,288
CO	5,470	5,285	10,755	4,116	3,214	7,330
H_2S	-	95	95	-	170	170
Aldehydes	184	7	191	138	5	143
NH_3	-	17	17	-	18	18
Fugitive Dust	2,248	-	2,248	1,637	-	1,637

Table 6.20. Uncontrolled Liquid Effluent Stream Concentrations (mg/l)

	NDL System	SIB System
Suspended Solids	64	600
Dissolved Solids	6,350	6,350
Organics	6,600	2,600
COD	38,000	15,000

Annual water emissions are based on these concentrations, and the assumption that half of the consumptive water use, or 650 gpm, is discharged. No water residuals result from the NDL system because onsite disposal is also assumed; these effluents thus become solid wastes or sludges. Control efficiency for suspended solids for the SIB system is assumed to be 99.5%; this amount is disposed of onsite and also becomes solid waste. Annual water residuals are shown in Table 6.21.

6.5.3 Solid Wastes and Sludges

Materials that contribute to the generation of solid wastes and sludges include ash from gasifiers and steam boilers, salts and silt from water treatment, ammonia still wastes, sludges from the biological treatment unit, and mine wastes.

Table 6.21. Annual Water Residuals (tons/year)

	NDL System[a]	SIB System
Suspended Solids	0	43
Dissolved Solids	0	9,030
Organics	0	3,700
COD	0	21,330

[a]Assumes onsite disposal of waste stream.

All ash contained in the gasifier feed coal and all ash in the auxiliary boiler coal, less that emitted as fly ash, is assumed to contribute to solid wastes. Ammonia still waste is estimated to be 0.5 tons/ton of ammonia produced.[59] Biological treatment sludge or domestic waste sludges constitute 1 ton/day for each system.[60]

Solids and organics not discharged to offsite water bodies contribute to solid waste as does 17 pounds of mine waste per ton of mined coal. No solid or sludge waste is generated by the sulfur removal plant because regenerative sulfur dioxide control has been assumed. (The assumption of lime or limestone scrubber SO_2 control would add 10 tons of sludge per ton of sulfur recovered from the flue gas stream.)

Table 6.22 summarizes the annual solid and sludge residuals generated by each of the reference systems. Generally, these wastes would be disposed of in the mine pit and covered with at least 10 ft of soil during reclamation.

Table 6.22. Annual Solid and Sludge Wastes (tons/year)

	NDL System	SIB System
Ash (solid)	906,730	905,312
Mine Waste (solid)	104,060	69,590
Ammonia Still Waste (sludge)	41,975	44,256
Waste Water Disposal (sludge)	18,505	4
Biological (sludge)	365	365
Total	1,071,635	1,019,527

6.5.4 *Occupational Health and Safety*

Occupational injury and fatality rates for coal gasification plants are estimated from data on the experience of natural gas processing and oil refining industries during 1968 and 1969.[61] During this period, 426.8 million man-hours were expended, and 40 fatalities and 2717 nonfatal disabling injuries were recorded. Loss of productivity as a result of these incidents was 53 man-days per nonfatal injury and 6300 man-days per fatality.

Both the NDL and SIB reference plants employ 750 persons. Each of these is assumed to work 2000 hours per year for an annual labor effort of 1.5 million man-hours. Thus, each plant is assumed to have 9.549 nonfatal disabling injuries and 0.141 fatalities per year.

In addition to plant personnel, 375 and 300 persons, respectively, are employed in mining activities to support the NDL and SIB plants. In 1970, 29 fatalities and an estimated 1058 nonfatal disabling injuries occurred during 45.3 million man-hours of surface mining activity. Severity rates of 60 man-days per injury and 6300 man-days per fatality have been estimated.[62] Injuries and fatalities associated with the respective mining activities are summarized in Table 6.23 together with data on plant operations.

6.5.5 *Nonoccupational Human Health*

During coal gasification processes, substances that are potentially hazardous to human health are produced. The extent to which many of the materials are emitted from process effluent streams is not yet known. It is believed that many of these materials can be confined to the system or technologically controlled so that no dangers to human health are posed. Many of these substances have been identified and are listed in Table 6.24.

Table 6.23. Annual Injury and Fatality Rates for the Coal Gasification Reference Systems

	NDL System			SIB System		
	Mine	Plant	Total	Mine	Plant	Total
Fatalities	0.480	0.141	0.621	0.384	0.141	0.525
Injuries	17.516	9.549	27.065	14.013	9.549	23.562
Man-days lost	4075	1394	5469	3260	1394	4654

Table 6.24. Potentially Hazardous Substances Suspected Present in Coal Conversion Process Streams

Chemical Classification	Compound	Phase
Acids and Anhydrides	Maleic Acid	liquid
	Cresylic Acid	liquid
	Sulfuric Acid	liquid
	Anthraquinone Disulfuric Acid	liquid
Alcohols	Aliphatic Alcohols	liquid
	Aromatic Alcohols	liquid
Amines	Diethylamines	gas
	Methylethylamines	gas
	Ammonia	gas/liquid
Inorganic Salts	Ammonium Sulfate	liquid
Carbonyl Compounds	Ketones	gas/liquid
	Aldehydes	gas/liquid
Combustion Gases	Carbon Monoxide	gas
	Sulfur Oxides	gas
	Nitrogen Oxides	gas
Heterocyclics	Pyridines	gas/liquid
	Pyrroles	gas/liquid
	(Mono) Benzofurans	gas
Hydrocarbons	Benzene	gas/liquid
	Toluene	gas/liquid
	Xylene	gas/liquid
	Aliphatics	gas
	Olefins	gas
Phenols	Phenols	gas/liquid
	Dimethyl Phenol	liquid
	Cresols	gas/liquid
	Xylanols	gas/liquid
	Phenyl Phenols	gas
	Alkyl Phenols	gas
	Alkyl Cresols	gas
Polynuclears	Anthracenes	gas
	Benzo (a) pyrene	gas
	Benzo (b) pyrene	gas
	Perylene	gas

Table 6.24. (Cont'd)

Chemical Classification	Compound	Phase
Polynuclears (cont'd)	Benzo (g,h,i) perylene	gas
	Coronene	gas
	Phenanthrene	gas
	Fluoranthrene	gas
	Chrysene	gas
	Benzo (a) anthracene	gas
	Acridine	gas
	Benzo (a) anthrone	gas
	Dibenzo (a,l) pyrene	gas
	Dibenzo (a,h) pyrene	gas
	Dibenzo (a,i) pyrene	gas
	Methyl Pyrene	gas
	Indeno (1,2,3-c,d) pyrene	gas
	Benzoacridine	gas
Sulfur Compounds	Sulfides	liquid
	Sulfonates	liquid
	Mercaptans	gas
	Thiophenes	gas/liquid
	Hydrogen Sulfides	gas/liquid
	Methyl Mercaptans	gas/liquid
	Carbon Disulfides	gas
	Carbonyl Sulfide	gas
	Methyl Thiphene	gas
Trace Elements	Vanadium	gas/liquid
	Nickel	gas
	Lead	gas
	Cobalt	gas
	Molybdenum	gas
	Strontium	liquid
	Beryllium	gas
	Selenium	gas/liquid
	Cadmium	gas
	Mercury	gas
	Antimony	gas
	Arsenic	liquid
	Phosphorus	gas/liquid
	Manganese	gas
Organo-metallics	Nickel Carbonyl	gas
	Cobalt Carbonyl	gas
Fine Particulates	Sulfur Particulates	gas
	Catalyst Fines	gas

Table 6.24. (Cont'd)

Chemical Classification	Compound	Phase
Fine Particulates (cont'd)	Coke	gas
	Coal Dust	gas
Cyanides	Hydrogen Cyanide	liquid
	Ammonium Thiocyanate	liquid

Source: G. Cavanaugh, et al., *Potentially Hazardous Emissions from the Extraction and Processing of Coal and Oil*, EPA-650/2-75-038, U.S. Environmental Protection Agency, Washington, D.C., April 1975, cited in U.S. ERDA and Department of the Interior Synthetic Fuels Commercialization Program Draft Environmental Statement, pp. IV-19 to IV-21.

A recent study by Mitre Corp. has identified many of these and other compounds as probable or potential human carcinogens. These are listed in Table 6.25.

Many of the organic carcinogens are expected to exit the gasification process in tar by-products. Recent studies on various coal types have shown that the tar by-products of the gasification process do contain traces of organic carcinogens.[63]

Because traces of heavy metals are contained in coal, some release of these is anticipated to accompany coal gasification. Of particular importance are the elements of arsenic (As), Mercury (Hg) and Lead (Pb), which are among the most volatile and thus may be contained in the gaseous effluents from the plant. These elements may have the most direct deleterious effect on human health. At least 22 other trace elements are known to be contained in domestic coals. After gasification the chemical phase and ultimate fate of at least half of these trace elements is still unknown.[64]

Lead, tellurium, mercury, selenium, nickel, chromium, and vanadium are all known to be highly toxic, with many exhibiting a special propensity for cellular deposition and retention.[65] These elements are capable of interfering with and disrupting the function of the central nervous system and other organ systems of the body. Table 6.26 summarizes the relative concentrations of trace elements in representative Central Interior and Northern Great Plains coals. As can be seen, those volatile and highly toxic elements previously mentioned (As, Hg, Pb) are found in higher concentrations in the

Central Interior coals. Thus, it might be anticipated that gasification of Southern Illinois bituminous coal would have more of a harmful impact from trace elements than would the gasification of North Dakota lignite.

Table 6.25. Potential and Known Human Carcinogens Found during Coal Gasification

POLYNUCLEAR AROMATIC HYDROCARBONS
Benzo (a) pyrene
Dibenz (a,h) anthracene
Benz (a) anthracene
Dibenzo (a,l) pyrene
Indeno (1,2,3,-cd) pyrene
Benzo (b) fluoranthene
Benzo (j) fluoranthene
Dibenzo (a,h) pyrene
Benzo (e) pyrene
Chrysene
POLYNUCLEAR AZA-HETEROCYCLIC COMPOUNDS
Benz (c) acridine
Dibenz (a,h) acridine
Dibenz (a,j) acridine
AROMATIC AMINES
2-Naphthylamine
1-Naphthylamine
BENZENE
PHENOL
Co-carcinogen
TRACE ELEMENTS
Arsenic
Beryllium
Cadmium
Chromium
Cobalt
Iron
Lead
Nickel
Selenium

Source: Mitre, *Coal Conversion Processes: Potential Carcinogenic Risk* (n.d.), cited in Johnson, Berinda, *Draft IR & T Data Package #3 Coal Gasification*, ERDA, pp. 11, 12 (April 15, 1977).

Table 6.26. Elements Found in Representative Coals[a]

Element	Central Interior Coal	Northern Great Plains Coal
Si	1.4%	1.1%
Al	0.77%	0.59%
Ca	0.50%	0.92%
Mg	0.063%	0.245%
Na	0.026%	0.100%
K	0.11%	0.037%
Fe	2.3%	0.45%
Mn	72 ppm	34 ppm
Ti	0.040%	0.037%
As (volatile)	12 ppm	2 ppm
Cd (volatile)	0.12 ppm	0.2 ppm
Cu	16.3 ppm	7.4 ppm
F	58 ppm	37 ppm
Hg (volatile	0.10 ppm	0.06 ppm
Li	7.0 ppm	4.3 ppm
Pb (volatile)	19 ppm	4.3 ppm
Sb (volatile)	0.8 ppm	0.4 ppm
Se (volatile)	2.8 ppm	0.5 ppm
Th	1.6 ppm	2.4 ppm
U	1.4 ppm	0.7 ppm
Zn	58 ppm	12.8 ppm
B	50 ppm	70 ppm
Ba	30 ppm	300 ppm
Be (volatile)	1.5 ppm	0.3 ppm
Co	7 ppm	1.5 ppm
Cr (volatile)	10 ppm	3 ppm
Ga	3 ppm	2 ppm
Mo	2 ppm	1.5 ppm
Nb	0.7 ppm	3 ppm
Ni (volatile)	18 ppm	2 ppm
Sc	3 ppm	1.5 ppm
Sr	30 ppm	100 ppm
V (volatile)	20 ppm	7 ppm
Y	7 ppm	3 ppm
Yb	0.7 ppm	0.3 ppm
Zr	10 ppm	15 ppm

[a]Representative values from a wide sample of coals.

Source: Ref. 65, p. 55, Habegger, L.J., A.J. Dvorak, et al.

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22. See Ref. 5, Secs. 1 and 3.

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31. See Ref. 12, p. 1-51.

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7 GAS TRANSMISSION PIPELINES

7.1 RELATIONSHIP WITH ALTERNATIVE SUPPLY SYSTEMS

In the preceding sections, the alternative technologies for gas supply were characterized and defined in terms of reference systems, each with an average sendout of 250 MMcfd. For each reference system definition, it was necessary to locate the technology in an area from which its supply could be conveniently derived. The lignite gasification system, for example, is located in Mercer County, North Dakota, where ample supplies of surface minable lignite are located. The bituminous gasification system, on the other hand, has been located in Fulton County, Illinois, near sufficient quantities of Illinois bituminous coals. The LNG importation terminal and the offshore system processing plant were located along the gulf coast of Louisiana.

Because of the wide differences in system locations relative to the Chicago-Northern Indiana market region, the social cost associated with the transmission of gas from each of these various locations, also has to be considered. The costs of transmission can be expected to vary between the systems as a result of differences in transmission distances and the availability or lack of an existing transmission pipeline network with sufficient capacity to transport an additional 250 MMcfd supply increment.

The location of the LNG importation and offshore production systems along the Louisiana coast is in an area that has a highly developed oil and gas production industry. The gas industry that has developed in this area has spawned an extensive network of transmission pipelines routed through a corridor that extends north to Illinois and Indiana, and northeast to the Ohio, Pennsylvania, and the New York area. This pipeline system transported approximately 13,070 MMcfd of gas produced along the Texas and Louisiana gulf coasts and in northern Louisiana to northern and northeastern markets during 1974. Because of the expanse of this pipeline network, it is assumed that the reference systems located along the Gulf coast will not require new pipeline construction. Installation of either the LNG or the offshore system in the 1985-1990 era may, in fact, represent a replacement of declining onshore supplies now being produced in this general region.

The coal gasification systems are located in regions that at present are not transporting natural gas to the Chicago-Northern Indiana area. The

North Dakota gasification system is located in a predominately rural region that has no major gas pipeline connections with the market area. The potential may exist, however, for an interface of a North Dakota coal gasification plant with the proposed North Border pipeline designed to transport 4.5 bcf per day of Alaskan natural gas through Montana, North and South Dakota, Minnesota, and Iowa and to terminate at Dwight, Illinois, 60 miles southwest of Chicago. The North Border proposal has recently won the recommendation of various FPC members, but full commission approval has not yet been granted. Although this alternative may be available in the future, the construction of a new transmission pipeline directly associated with the North Dakota lignite gasification system is considered in this assessment. The route of this pipeline will be nearly the same as that planned in the North Border proposal.

The Illinois gasification system is in a general area that is crossed by two major interstate pipelines transporting gas from the Texas and Oklahoma panhandle regions to the Chicago-Northern Indiana market area. Each of these lines is operating at near full capacity and is not considered capable of transporting an additional 250 MMcfd. Hence, a newly constructed pipeline is also assumed for the Illinois gasification system.

7.2 INTERSTATE TRANSMISSION PATTERNS AND SYSTEM CHARACTERISTICS

7.2.1 Transmission Patterns

During 1974, interstate pipeline companies transported approximately 15 trillion cubic feet (tcf) of domestically produced and imported gas. This quantity accounted for about two-thirds of the total gas movement within the United States during that year.

A recent FPC Staff Report[1] has described in detail the gas flow patterns for each of 106 interstate pipeline companies and has aggregated these data in terms of regional supply and market areas. Figure 7.1 summarizes and graphically illustrates the 1974 net interstate gas transfers between the major areas. Chicago and northern Indiana are part of the Great Lakes market area which includes Wisconsin, Illinois, Indiana, and Michigan. During 1974, over 54% of the interstate gas transported to this area originated from the southern Louisiana and the Texas gulf coast supply regions. Another 37% was supplied

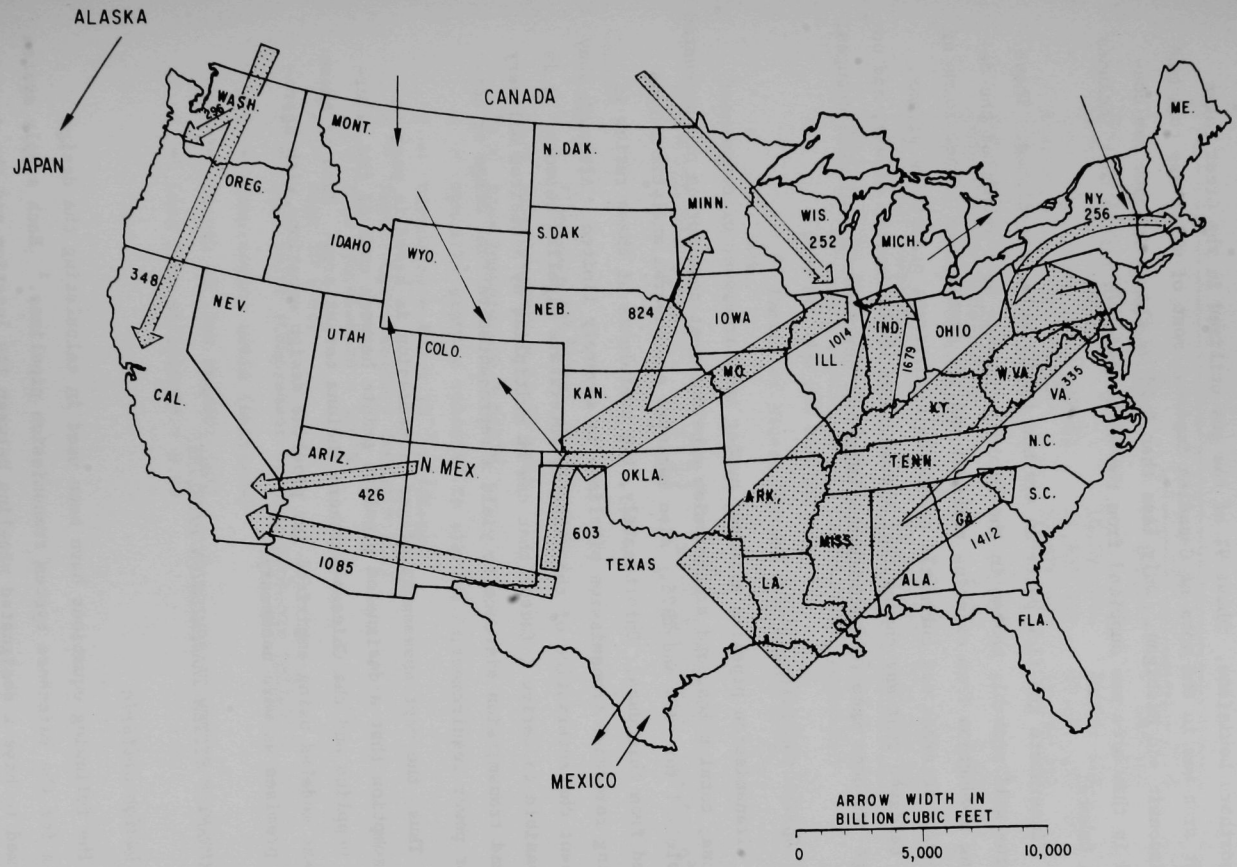

Fig. 7.1. U.S. Gas Transmission Flow Patterns, 1974

from the Texas and Oklahoma panhandle regions, eastern Oklahoma, Arkansas, and northern Louisiana. About 9% of the gas utilized in the Great Lakes market area was in the form of Canadian imports, most of which was consumed in Wisconsin and Michigan. Only less than 0.2% of the interstate gas consumed in this area was supplied from the Rocky Mountain region that includes North Dakota.

Interstate gas flow patterns are now fairly well established. These patterns will probably change in the future primarily as a result of the declining production from existing reserves and the development of new forms of gas supply in areas not currently producing significant quantities of gas. It is believed that any change that should occur would develop slowly, and no attempt has been made to quantify the magnitude nor direction of such changes.

7.2.2 System Characteristics

Transmission pipeline mileage, number and horsepower of compressor stations, total sales, and transmission pipeline fuel consumption are presented in Table 7.1 for 1974 and 1975. Also included are several analytic ratios derived from this data. Unfortunately, the usefulness of these ratios in defining reference transmission pipelines is severely limited. Although they represent characteristics of the existing interstate pipeline network, it is not possible to derive a factor that can be multiplied by a desired delivery rate and transmission distance to yield a representative fuel usage or compressor power requirement.

Thus, the cost assessment of gas transmission is based in part on the assumption that a designated pipeline exists between each of the alternative supplies and the Chicago-Northern Indiana market area. Each of these lines was modeled using empirical gas pipeline design equations with appropriate premises as were necessary.

7.3 REFERENCE SYSTEM TRANSMISSION PIPELINES

7.3.1 Design Criteria

The following equations have been used in calculating the design criteria for the reference system transmission pipelines.[2] Each supply system is assumed to have a designated pipeline between its location and the demand area.

Table 7.1. Transmission Pipeline System Characteristics

	1974	1975
Transmission pipeline (mi)	186,883	186,566
Transmission compressor stations	945	1,029
Trans. compressor hp	10,594,494	12,082,616
Total interstate sales (MMcf)	17,835,495	16,649,953
End-Use deliveries (MMcf)	19,076,955	17,558,353
Compressor hp/mi of transmission pipeline	56.69	64.76
MMcf end-use/installed hp	1.80	1.45
Pipeline mileage/compressor station	197.75	181.30
Compressor hp/station	11,211.00	11,742.00

Sources: The Petroleum Publishing Company, *Worldwide Directory Pipelines and Contractors*, Reprinted from *Oil and Gas Journal*.

U.S. Bureau of Mines, *Natural Gas Annual 1974, 1975*.

$$Q = 211.35 \times \frac{To}{Po} \times \left(\frac{1}{G}\right)^{0.46} \times \left(\frac{1}{Z}\right)^{0.081} \times \left(\frac{DP^2(1-1/R^2)}{TL}\right)^{0.541} \times E \times D^{2.624} \quad (1)$$

where:

Q = Flow rate (ft^3/day) at To and Po

Po = Base pressure = 14.73 psia

To = Base temperature = 520°R

G = Specific gravity relative to air = 0.63

Z = Viscosity = 8.3×10^{-6} lb/ft-sec

B = Supercompressibility factor = 1.12

T = Flow temperature = 520°R

D = Pipe ID (in.)

P = Line inlet (Compressor outlet) pressure (psia)

R = Compression ratio (unitless)

L = Length of line segment (mi)

E = Line flow efficiency = 0.90

$$H = \frac{3.03\ n\ Po\ Ts}{E\ (n-1)\ To} \times \left(R^{\frac{n-1}{n}} - 1 \right) + K \qquad (2)$$

where:

H = Brake horsepower per MMcf per day at Po and To

Po = Base pressure = 14.73 psia

To = Base temperature = 520°R

Ts = Suction temperature = 520°R

n = specific heat ratio = 1.3

R = Compression ratio (unitless)

E = Compressor efficiency = 0.90 for reciprocating units
0.80 for centrifugal units

K = Valve losses = 3.0 hp/MMcfd for reciprocating units
No value losses for centrifugal units

Several assumptions were required in utilizing these equations. In particular, since a flow rate (Q) of 250 MMcfd is fixed, three of the four variables D, P, R or L had to be assumed in Eq. 1. Also, it was necessary to choose the type of compressor unit desired. The approach taken was to select reasonable values for D, P, and R, and then to calculate L, the distance between compressor stations, since this variable was considered least restricted in terms of the overall system design. Centrifugal compressor units were chosen because of their overall higher efficiency.

Transmission of 250 MMcfd of natural gas can be accomplished most economically utilizing a 26 inch OD pipeline. Typical pipelines of this size have wall thicknesses of 0.312 inches and thus inside diameters of 25.376 inches.[3] Typical pipeline inlet pressures (and compressor outlet pressures) average around 1000 psia with compression ratios between 1.3 and 1.4.[4] Some high pressure systems have inlet pressures in the neighborhood of 1450 psia, as is currently planned for the North Border System,[5] but maintain compression ratios of 1.3 and 1.4. For the reference pipelines, the inlet pressure is taken to be 1000 psia and the compression ratio to be 1.32. Thus the delivery or subsequent compressor inlet pressure is about 758 psia.

In defining the reference pipeline systems, two assumptions were made: (1) that each compressor station is designed with a 50% peaking margin, allowing for 50% more compressor horsepower than required by Eq. 2; and (2) for ease of calculation, the pipeline losses due to compressor fuel usage

and leakage would not significantly alter the design criteria. (Had the design been tailored to account for these losses, only a 5% reduction in compressor horsepower would have resulted over a transmission distance of 1000 miles.)

The distances between the Gulf coast system (LNG importation and offshore production), the North Dakota lignite gasification system, and the Chicago-Northern Indiana market region, are nearly the same and approximately equal to 900 miles. The Illinois bituminous gasification system is located approximately 180 miles from the market area. Equation 1 requires a compressor station every 180 miles; and with a 50% peaking requirement, Eq. 2 requires that each station have a total installed capacity of 6000 horsepower. Thus, the offshore production system, the LNG importation system, and the North Dakota lignite gasification system require a transmission system with 4 compressor stations at 180-mile intervals for a total installed capacity of 24,000 horsepower. The Illinois bituminous gasification system, on the other hand, requires only 180 miles of pipeline. A 1000 psia exit pressure at the plant is sufficient to transport the gas to the market region without additional compression.

7.3.2 Fuel Consumption and Line Losses

Compressor drives (gas turbines or reciprocating engines) are assumed to operate at a 28% efficiency. This value is considered as an annual average but will, in practice, vary nonlinearly with pipeline load. The average load factor on each of the compressor stations is 67% or an average power output of 4000 hp. Hence, each of the 900-mile lines requiring four such stations would consume 318 x 10^9 Btu of fuel each year. The actual volume of fuel used is dependent on the average heating value of the product gas. Table 7.2 reviews these values and summarizes the pipeline fuel usage for each reference supply system.

During 1975 a total of 235,065 MMcf of natural gas was lost or unaccounted for from pipeline systems in the United States.[6] With the operation of 262,000 miles of transmission pipelines during that year, an annual unit loss of 0.895 MMcf/mile may be estimated. Losses assignable to each of the reference system pipelines are also included in Table 7.2.

Table 7.2. Reference Transmission System Fuel Usage and Pipeline Losses

System	Offshore	LNG Import	NDL	SIB
System Output Capacity (MMcfd)	250	250	250	250
Product Heating Value (Btu/cf)	1024	1015	970	970
Transmission Distance (mi)	900	900	900	180
Installed Compressor Drive (hp)	24,000	24,000	24,000	0
Annual Energy Use (10^{12}Btu)	1.272	1.272	1.272	0
Daily Fuel Use (MMcfd)	3.40	3.43	3.59	0
Pipeline Losses (MMcfd)	2.21	2.21	2.21	0.44
Deliverable Capacity (MMcfd)	244.39	244.36	244.20	249.56
Deliverable Capacity (10^{12}Btu/yr)	91.34	90.53	86.46	88.36

7.3.3 Land and Water Requirements

Two recent pipeline construction proposals were reviewed to estimate land and water requirements. A 418-mile, 24-inch pipeline (Refugio Waha) proposal estimates land usage to be 31,000 acres for right-of-way, 400 acres for access roads and storage areas, and 8-10 acres for each compressor station. The right-of-way for this line averages 60 feet in width. The 42-inch North Border pipeline, on the other hand, is designed with a 100-foot right-of-way.[7]

Based on these data, the reference system pipeline was assumed to have an associated right-of-way of 75 feet, or 81.8 acres per line mile. Access roads and other surface uses are estimated at 0.5 acre/mile of pipeline. Compressor station sites are assumed to encompass an additional 5-10 acres each. Thus a 900-mile line with four compressor stations would use 75,000 acres of land. Of this, only 480 acres would be associated with above-ground facilities. The 180-mile line assumed for the Southern Illinois gasification system would require a total of 14,814 acres, only 90 acres of which would be associated with above-ground access roads; no compressor stations are required.

No significant or notable water uses are associated with the operation of gas transmission pipelines. Water is used for hydrostatic testing during construction, but its use is temporary and considered minor. Nevertheless, normal construction practice is to utilize the same water to test several

sections of the same pipeline, thus minimizing any potential impact of its use.

7.3.4 Employment

Construction Manpower. Pipeline construction manpower requirements vary from project to project because of differences in pipe diameter, terrain, and the number and types of river crossings required. Three recent pipeline proposals have been reviewed and data characterizing their construction schedules are summarized in Table 7.3.

Under normal conditions, pipelines are constructed simultaneously in several segments or *spreads*, each of which may be 70-100 miles or more in length. The general procedure involves clearing and grading of the right-of-way; stringing the pipe, trenching, lining-up, and welding; coating and lowering in; backfilling, restoration, and, finally, hydrostatic testing. Crossing under roads and waterways generally requires special techniques of tunneling and barge laying.

Table 7.3. Pipeline Construction Manpower Requirements

Project	North Border	Refugio-Waha	Great Lakes
Diameter (in.)	24-42	24	30
Length (mi)	1619	418	365
Const. period (mo.)	16	7	8
Avg. manpower (men)[a]	6130	1380	2010
No. spreads	NR[b]	6	4
Pipeline const. man-years	8173	805	1340
Man-years/mi	5.05	1.93	3.67
Compressor hp/station	30,000	24,100	None
Avg. mpwr./station (men)	48	100	-
Station const. period (mo.)	0.8	1.73	-

[a]15% added to construction workers for survey and right-of-way acquistion.

[b]NR - not reported.

Source: Sargent and Lundy Engineers, *Technology Characterization High Btu Gas Transmission.*

With regard to the terrain being crossed, the North Border pipeline is most representative of the new construction assumed necessary in this assessment, followed by the Great Lakes line, and finally the Refugio-Waha line. The North Border line, however, is of a much larger diameter with larger compressor stations than is assumed here. Thus, it is thought that construction manpower requirements associated with the reference system lines would be best represented by values intermediate to those presented for the Refugio-Waha and Great Lakes projects. Construction of the reference system lines is estimated to require three man-years of effort per mile of pipeline; construction periods are estimated at 18 months for a 900-mile line and 4 months for a 180-mile line; and construction of each of the 6000-hp compressor stations is assumed to require 50 persons and four months of activity.

Operating Manpower. Operating personnel required for the Refugio-Waha and the Great Lakes projects are estimated by the applicants to be about 0.03 persons per mile. The North Border pipeline estimates 0.12 persons per mile, a value consistent with overall transmission industry statistics between 1960 and 1975.[8] For this assessment the overall transmission industry value of 0.12 persons per mile is assumed.

7.3.5 Capital and Operating Costs

New Line Construction Costs. The average construction cost for a new 26-inch diameter gas transmission pipeline can be estimated from data compiled by the Petroleum Publishing Company.[9] The available data brackets the 26-inch diameter size with statistics on 24-inch and 30-inch lines. To estimate the costs of a 26-inch line, a value representative of this range was used. Table 7.4 summarizes these estimated costs in 1975 dollars. The materials component includes the pipe, coating material, and various fittings and valves. Indirect costs include engineering costs, general expenses, and contingencies.

These data estimate a unit construction cost of $220,000/mile. This estimate compares with actual costs of $249,600 and $212,215/mile for two 26-inch pipeline projects completed in 1975.

The estimated cost of $220,000/mile includes only the cost of the pipeline string and does not include the cost of necessary compressor stations. The average cost of installing 11 new turbine-centrifugal stations totaling 36,000 horsepower in 1975 was $570/hp. During the same year, the installation

Table 7.4. Unit Construction Costs for 26-Inch Gas Transmission Pipeline

Component	1975$/mi
Right of Way and Damages	12,500
Materials	96,000
Labor	90,000
Indirect Miscellaneous	21,500
Total	220,000

of 6 reciprocating stations cost $575/hp. These data suggest that the installation of a 6000-hp station would total about $3.45 million in 1975 dollars. Total construction costs for the reference systems requiring new pipeline construction are given in Table 7.5. A constant dollar interest rate of 3% for one year is assumed for each project.

Operation and Maintenance Costs. Estimated annual operation and maintenance costs for two recently proposed pipelines range from $7071-$5214/mile. The larger value is the unit operation and maintenance cost for a 30-inch, 365-mile pipeline project proposed by Great Lakes Gas Transmission Company. The lower value is the estimated operation and maintenance cost for the 24-inch, 418-mile Refugio-Waha pipeline project. An itemization of these costs is included in Table 7.6. Based on these values, a 1975 constant dollar O&M cost of $6800/mile per year was selected.

Table 7.5. Transmission Pipeline Construction Characteristics and Costs

Reference System	North Dakota Lignite Gasification	Illinois Bituminous Gasification
Characteristics:		
Distance (miles)	900	180
Compressor Stations	4	0
Total Horsepower	24,000	0
Costs: (million 1975$)		
Line Direct and Indirect	198.0	39.6
Compressor Station Direct & Indirect	13.8	0.0
Interest during Construction	6.4	1.2
Total Investment	218.2	40.8

Table 7.6. Itemization of Annual Pipeline Operation and Maintenance Costs

Owner	Great Lakes[a]	Refugio-Waha
Diameter (in.)	30	24
Length (mi)	365	415
O & M Costs: ($/mile)		
Property and ad valorem taxes	5802	3180
Transmission expenses	624	1506
Administrative & general overhead	645	528
Total O & M	7071	5214

[a]Original 1974 values escalated 8% to 1975.

Source: Sargent and Lundy Engineers, *Technology Characterization High-Btu Gas Transmission.*

Operation and maintenance costs are assumed to increase at 1.5% above an annual inflation rate of 6%. Levelizing these costs over a 20-year period results in an annual constant-dollar, levelized charge of $7500 per mile.

Cost of Service for New Lines. The cost of service for newly constructed gas transmission pipelines can be arrived at by applying a constant dollar annual charge rate to the initial capital investment and then adding levelized annual operating and maintenance costs. A constant dollar annual charge rate of 12% for pipeline company investments with 20-year service lives is assumed. This figure is based on a 60:40 debt-equity ratio, 9% current dollar interest, 15% current dollar rate of return, 6% inflation and a 48% incremental tax rate. Levelized annual operation and maintenance charges, based on 1.5% per year escalation over inflation, are $7500 per line mile yearly.

Applying the annual charge rate to the new line invested capital and adding the levelized annual O&M charge of $7500/mile results in a cost of service of $32.93 million per year for a new 900-mile line transporting gas from Mercer Co., North Dakota, to the Chicago-Northern Indiana area. The annual cost of service for a new 180-mile line between Fulton Co., Illinois, and the market area would be $6.25 million. Approximately 80% of these revenue requirements result from capital charges; 20% from labor. Final cost per unit of gas delivered is dependent on fuel use and pipeline losses over the distance transported.

Cost of Service for Existing Lines. The cost of service for gas transmission through existing lines is somewhat lower because these systems were constructed before 1975 at lower costs. An estimate of this value may be obtained from 1975 statistics on 34 major interstate natural gas pipeline companies.[10,11,12] During 1975 these companies received operating revenues totaling $12,352,562,000 and operated 159,541 miles of transportation pipeline. Part of the operating revenues covered expenses for gas purchases; $7,043,779,000 were used for this purpose. Thus, $5,308,783,000 covered capital depreciation, salaries, taxes, interest on bonds, and return on investments. Dividing this figure by the mileage of lines operated during 1975 gives an estimated annual cost of service of $33,275/pipeline mile. Of this value, $6800/mile is estimated for O&M and $26,475/mile is for capital charges. Because the capital component was fixed in previous years and is not subject to change, it may be considered a constant 1975 dollar charge. The operation and maintenance component is assumed to escalate at 1.5% above a 6% inflation level, and the levelized constant dollar annual O&M cost (20 yr) is $7500/mile. Thus, revenue requirements for an operating transmission pipeline is $33,975 per mile or $30.58 million per year for a 900-mile line.

7.4 RESIDUALS

7.4.1 Air

Environmental residuals resulting from the operation of gas pipeline compressors in 1973 were estimated by Southwest Research Institute (Southwest) in the results of a study published in 1975.[13] Emission factors were derived from the actual testing of representative compressor drives. The gas transmission industry was then surveyed to determine the nature of its installed compressor horsepower and the emission factors were applied appropriately. The Southwest survey accounted for 86% of the gas industry's installed horsepower over 1000 -- 75% of the total installed compressor horsepower.

Emission factors applied to the reference system pipelines are mainly derived from Southwest's results. Because they did not estimate SOx or particulate emissions, these values are derived from the EPA's air pollutant emission factors.[14] Table 7.7 presents the emission factors for pipeline compressor stations.

Table 7.7. Pipeline Compressor Station Emission Factors

Drive Type	Emission Factor (lb/hp-hr)[a]				
	Particulates	NOx	SOx[b]	Hydrocarbons	CO
Gas Engines	NR[c]	2.46×10^{-2}	1.53×10^{-6}	9.55×10^{-3}	2.96×10^{-3}
Gas Turbines	1.27×10^{-4}	3.09×10^{-3}	1.72×10^{-6}	1.44×10^{-4}	7.67×10^{-4}
1973 Turbine Engine Mix	1.27×10^{-4}	1.84×10^{-2}	1.58×10^{-6}	6.86×10^{-3}	2.33×10^{-3}

[a]Based on gas heating value of 1000 Btu/cf

[b]Based on 0.2 grains total sulfur per 100 cf (0.00069 wt %)

Total Sulfur concentrations are:

Offshore Production	0.2 grains/100 cf (0.00069 wt %)
LNG Importation	3.0 grains/100 cf (0.10 wt %)
Coal Gasification (Both NDL & SIB)	7.5 grains/100 cf (0.026 wt %)

Source: Refs. 13 and 14.

Emission factors were calculated on the premise that those systems utilizing existing pipelines (LNG importation and offshore production) would have a mix of compressor drives similar to that existing in 1973 -- 71.4% gas engines and 28.6% gas turbines; new pipelines would use only gas turbine drives. Table 7.8 summarizes the annual air emissions from each of the pipeline systems.

7.4.2 Water

No significant or notable water pollutants result due to the operation of the reference gas transmission pipelines.

7.4.3 Occupational and Nonoccupational Safety

During 1975 the natural gas utility industry experienced 9.27 disabling injuries and 570 man-days lost per million man-hours worked. Also during this year, the industry fatality rate was 0.054 deaths per million man-hours.[15] Assuming 6300 man-days lost per fatality results in an additional 340 man-days lost per million man-hours worked each year.

Table 7.8. Air Residuals from Pipeline Systems

System	Emissions (Tons/yr)[a]					
	NOx	CO	Hydrocarbons[b]	SOx	Particulates	H_2S[c]
Offshore	1260	159	469 (16,750)	0.11	9	.06
LNG Import	1270	160	473 (16,750)	1.64	9	.06
NDL	223	55	10 (16,750)	4.38	9	.15
SIB	NA	NA	(3,330)	NA	NA	.03

[a]Adjusted for fuel heating value.

[b]Parenthetical value from line losses with density = 0.0415 lb/cf.

[c]Based on H_2S concentration in product gas and line losses.

H_2S concentrations are:

Offshore & LNG 0.1 grains/100cf = .0069 lb/ton hydrocarbon (CH_4)
NDL & SIB 0.25 grains/100cf = .0172 lb/ton hydrocarbon (CH_4)

NA = Not applicable.

During 1973, a total of nine nonoccupational injuries and one nonoccupational fatality resulted from the failure of gathering or transmission pipelines.[16] Gathering and transmission lines during 1975 totaled 331,100 miles, so 2.7×10^{-5} nonoccupational injuries and 3.0×10^{-6} nonoccupational fatalities per mile of operating pipeline may be estimated. For the purpose of this assessment, the number of man-days lost as a result of nonoccupational injuries and fatalities are at the same rate as those associated with occupational incidents. Table 7.9 summarizes the safety impacts associated with each of the reference system transmission segments. An employment of 0.12 persons per pipeline mile is assumed.

Table 7.9. Annual Injuries and Fatalities Associated with Gas Transmission

System	Offshore, LNG, NDL (900 mi)	SIB (180 mi)
Injuries		
Occupational	2.00	0.410
Nonoccupational	0.02	0.005
Total	2.02	0.415
Man days lost	124	25
Fatalities		
Occupational	0.012	0.0024
Nonoccupational	0.003	0.0005
Total	0.015	0.0029
Man days lost	95	18

7.5 *REFERENCES*

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3. U.S. Federal Power Commission, National Gas Survey, 5 vols., U.S. Government Printing Office, Washington, D.C., Vol. 3: *Transmission Task Force Reports*, p. 128 (1973).

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7. See Ref. 5, p. 33, Exhibit 26.

8. Ibid., pp. 12, 21, 31, 38.

9. Petroleum Publishing Company, *Worldwide Pipelines and Contractors Directory 1976*, Tulsa, Okla., pp. 6-23 (1976).

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11. U.S. Federal Power Commission, *FPC Releases Preliminary 1975 Statistics on Interstate Natural Gas Pipelines*, FPC News, 9(32):3-17 (Aug. 6, 1976).

12. U.S. Federal Power Commission, Washington, D.C., personal communications (1977).

13. Urban, C.M., and K.J. Springer, *Study of Exhaust Emissions from Natural Gas Pipeline Compressor Engines*, Southwest Research Institute, Project PR-15-61, p. 33, cited in Sargent and Lundy Engineers (Ref. 5), Exhibits 12-14.

14. U.S. Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, AP-42, 2nd ed., Research Triangle Park, N.C., pp. 3.3.1-1 to 3.3.1-3, 3.3.2-1 to 3.3.2-2 (Mar. 1975).

15. American Gas Association, *Gas Facts-1975*, Arlington, Va., pp. 191-192 (1976).

16. U.S. Department of the Interior, *Minerals Yearbook-1973*, 3 vols., Washington, D.C., Vol. 1: *Metals, Minerals, and Fuels*, p. 809, cited in Sargent and Lundy Engineers (Ref. 5), Exhibit 18.

8 SUMMARY AND COMPARISON

Four alternative high-Btu gas supply options -- offshore development in the Gulf of Mexico, Gulf Coast LNG importation, and first generation Lurgi gasification of North Dakota lignite and southern Illinois bituminous coals -- have been defined in terms of reference systems, each supplying an average of 250 million cubic feet per day of pipeline quality gas. Gas is assumed to be transported to and ultimately consumed in the Chicago-Northern Indiana area. In preceding sections, these alternative supply technology reference systems and their associated pipelines were characterized. This final section summarizes comparatively the social costs associated with the implementation of these alternatives in the 1985-1990 time frame. Where possible, the comparison is quantitative; where identifiable costs are not quantifiable, a qualitative discussion of the alternatives is presented.

8.1 QUANTIFIABLE SOCIAL COSTS

As an integral part of the preceding technology characterizations, quantifiable social costs were assessed and assigned to the respective gas supply option. Each of these costs are reviewed and summarized within this section, and can be categorized under one of the following three headings:

1. Conventional or Internal Costs,
2. Resource Use, or
3. Environmental Residuals

The manner in which the costs are presented facilitates comparison among the alternative technologies.

8.1.1 Conventional Costs

Conventional costs include all capital and operating costs that enter into the determination of price. For the purpose of this assessment, costs and rates are assumed to be as stated. All conventional costs are in constant 1975 dollars. Real escalation of material and labor costs during construction is assumed to be zero. Annual interest rates during construction are 3%, equal to the historic constant dollar interest rate on industrial construction capital; expenditure of construction capital follows representative cash flow curves with necessary capital committed at the beginning of the year in which it is required.

Table 8.1 summarizes the conventional costs for each of the four high-Btu gas supply options and associated transmission pipelines. The capital structure for offshore production was chosen to be 28% debt and 72% equity, which corresponds closely to the composite structure of U.S. oil companies producing over 90% of the gas in the Gulf of Mexico. Capital structure for each of the other systems and pipelines was chosen to be 60% debt and 40% equity, which approximates the capital structure of several large gas transmission companies. In each case, current dollar bond interest is considered as being 9% per year, current dollar return on equity 15%, and the incremental federal tax rate 48%. Annual operation and maintenance costs are assumed to escalate at 1.5% over an inflation rate of 6% per year. A constant dollar cost of capital (and annual charge rate) was applied to new capital expenditures, and constant dollar levelizing of operation and maintenance was used to calculate representative energy costs assuming 1985 start-up.

For the most part, gas transmission pipeline companies are showing strong interest in the supplemental supply options, including LNG importation and coal gasification. Although some pipeline companies also produce portions of their own gas supplies, major gas production activities are generally controlled by independent producers who sell to the pipeline companies. Independent producers carry heavy equity financing relative to pipeline companies and require a larger charge on invested capital to satisfy their financial requirements. An annual charge rate of 22% (which includes a 16.7% royalty on gross revenues) was used for the offshore production technology and 12% for the LNG and coal gasification options, and transmission pipelines.

The total invested capital necessary to develop similar-sized systems may vary by a factor of 2.0, as indicated in Table 8.1. The least capital-intensive system is the LNG importation option with a capital requirement of $609.2 million, followed by $627.1, $1138.7, and $1255.3 million required respectively for the offshore option, the NDL, and the SIB systems.

The LNG option also requires the smallest annual capital charge, estimated at $73.10 million, followed by $136.64, $137.96, and $150.64 million required respectively for the North Dakota lignite gasification, the offshore, and the bituminous gasification systems.

Table 8.1. Comparison of Alternative High-Btu Gas Supply System Conventional Costs

Technology	Offshore Gulf of Mexico		Liquefied Natural Gas Importation		North Dakota Lignite Gasification		Southern Illinois Bituminous Gasification	
Product Gas Heating Value	1024 Btu/cf		1015 Btu/cf		970 Btu/cf		970 Btu/cf	
Plant or Terminal Output	250 MMcfd		250 MMcfd		250 MMcfd		250 MMcfd	
Delivered Capacity	244.39 MMcfd (91.34 10^{-12}Btu/yr)		244.36 MMcfd (90.53 10^{-12}Btu/yr)		244.20 MMcfd (86.46 10^{-12}Btu/yr)		249.56 MMcfd (88.36 10^{-12}Btu/yr)	
Annual Charge Rate	22% (production only, includes royalties)		12%		12%		12%	
Service Life	15 years		20 years		20 years		20 years	
Transmission Pipeline	Existing		Existing		New		New	
Capital Costs[a]	Exploratory & Development Direct	$172.09	Terminal Direct	$ 96.90	Plant Direct	$ 878.80	Plant Direct	$ 940.60
	Exploratory & Development Indirect & IDC	79.63	Terminal Indirect & IDC	32.30	Plant Indirect & IDC	197.20	Plant Indirect & IDC	204.20
	Exploratory & Development	$251.72	Terminal	$129.20	Plant	$1076.00	Plant	$1144.80
					Mine Direct & Future Replacements	$ 47.70	Mine Direct & Future Replacements	$ 84.10
					Mine Indirect & IDC	15.00	Mine Indirect & IDC	26.40
	Lease Acquisition	$375.38	Three Transport Vessels	$480.00	Mine	$ 62.70	Mine	$ 110.50
	Total Capital	$627.10	Total Capital	$609.20	Total Capital	$1138.70	Total Capital	$1255.30
Annual Production Charges($$10^6$/yr)	Capital	$137.96	Capital	$ 73.10	Capital	$ 136.64	Capital	$ 150.64
	Levelized Total O&M (includes royalties)	$ 8.50	Terminal O&M	$ 5.00	Plant O&M	$ 66.62	Plant O&M	$ 66.62
			Vessel O&M	19.21	Mine O&M	34.20	Mine O&M	$ 24.98
			Total O&M	$ 24.21	Total O&M	$ 100.82	Total O&M	$ 91.60
	Other: None	-	Other: LNG Purchase	$165.00	Other: Royalties	$ 5.51	Other: Royalties	$ 5.25
	Total Charges	$146.46	Total Charges	$262.31	Total Charges	$ 242.97	Total Charges	$ 247.49
Transmission Charges ($$10^6$/yr)		$ 30.58		$ 30.58		$ 32.93		$ 6.25
Total Charges ($$10^6$/yr)		$177.04		$292.89		$ 275.90		$ 253.74
Unit Production Cost	$1.61/Mcf = $1.57/MMBtu		$2.87/Mcf = $2.83/MMBtu		$2.66/Mcf = $2.74/MMBtu		$2.71/Mcf = $2.79/MMBtu	
Unit Delivered Cost	$1.98/Mcf = $1.93/MMBtu		$3.28/Mcf = $3.23/MMBtu		$3.10/Mcf = $3.20/MMBtu		$2.79/Mcf = $2.87/MMBtu	

(a) Capital Costs for offshore system are 91% of total costs; remaining 9% assigned to gas liquids.

Levelized annual production charges, other than capital charges, include general operation and maintenance (O & M) expenditures and annual production related costs such as production unit royalties and supply purchases. The offshore production option requires $8.5 million per year in O & M. Production royalties for the offshore system are assessed at 16.7% of gross revenues. Thus, these charges have been included in the capital and O & M charges. LNG importation has the highest estimated annual operating charges totaling $189.2 million. Of this total, $5.0 million is for the O & M of the receiving terminal, $19.2 million for the O & M of three LNG tanker ships, and $165.0 million is required to purchase foreign LNG. The North Dakota lignite and southern Illinois bituminous gasification options require $106.3 and $96.8 million in annual O & M, respectively. In each case it is estimated that the gasification plant O & M would be $66.6 million per year with mining operations and unit production royalties making up the remainder of the costs.

Based on an average production volume of 250 million cubic feet per day (MMcfd) for each of the alternatives, unit production costs range from $1.61 per thousand cubic feet (Mcf) to $2.87/Mcf. Because of the small differences in heating value, the cost per million Btu (MMBtu) is not directly proportional to the cost per thousand cubic feet. Rather, the corresponding range of energy based unit production cost is $1.57/MMBtu for offshore production to $2.83/MMBtu for LNG importation. The supply of 250 MMcfd from Southern Illinois bituminous gasification is achievable at $2.79/MMBtu and that for North Dakota lignite gasification at $2.75/MMBtu. Thus, on an energy basis, lignite gasification, bituminous gasification and LNG importation are estimated to cost 75, 78 and 80% more than offshore production.

When coupled with the transmission pipeline linking each supply option with the Chicago-Northern Indiana demand region, gas produced from the offshore option and gas from imported LNG remain respectively the least and most costly to supply. Gas from the North Dakota lignite gasification option, however, becomes more costly than that of the Illinois bituminous system as a result of its higher transmission cost ($0.45/MMBtu vs. $0.08/MMBtu) and lower transmission efficiency (97.7 vs. 99.8%).

Thus, as a result of transmission costs, the relative rankings of options by final delivered cost is different than their rankings by production cost. These are summarized in Table 8.2.

Note that the final delivered prices referred to here are the constant 1975 dollar minimum acceptable prices desired by the *transmission* company upon sale of gas to *distribution* companies in the Chicago-Northern Indiana area. Typically, distribution costs will add another 85-90/MMBtu to the gas price; these costs will be passed through to the consumer.

Factors other than the capital expenditures and final delivered cost must also be considered in assessing these alternatives. Other considerations to be recognized include the investor's ability to generate the required capital funds necessary to pursue a given option, the price security of feed supplies, options for shared costs, and the sensitivity of price to any single high-cost item.

Gas transmission pipeline companies have shown interest in LNG importation and coal gasification. Usually, these companies are not capital intensive, and thus will find it difficult to finance such ventures. In this respect, imported LNG may be an attractive option to them, since its total capital cost is $529.5 million less than the least-cost gasification alternative (not including new transmission facilities necessary for the gasification options). A further reduction in capital requirements is possible if some or all of the tanker ships are provided by the exporter, or leased.

Table 8.2. Ranking of Gas Supply Options by Conventional Costs

	Production Cost		Delivered Cost	
Rank		Increase over Least-Cost Option		Increase over Least-Cost Option
1	Offshore	Least $ Cost	Offshore	Least $ Cost
2	Lignite Gasification	75%	Bituminous Gasification	49%
3	Bituminous Gasification	78%	Lignite Gasification	66%
4	LNG	80%	LNG	67%

Capital cost reductions are also possible with coal gasification, but to a lesser extent. With either gasification option, a gas company could purchase coal from a mining company and thus avoid capital investment in mining. The result, however, would be to reduce capital requirements by 6-10% as compared to the 26-80% that may be possible for LNG. The cost of feed coal would also be higher if purchased from a mining company, since the market value of coal is considerably higher than the pass-through cost of coal from a utility-owned mine.

Gas provided by increases in offshore production activities requires the second smallest capital investment, and the primary participants in offshore ventures are very highly capital- and equity-intensive oil companies. Although these companies should not experience problems in generating the necessary capital, large uncertainties exist regarding future capital costs. The largest of these results from estimates of future lease acquisition costs. Since 1970, annually averaged offshore lease acquisition costs in general lease sales have varied by as much as 50-100% and more. Since the lease acquisition cost makes up 56% of the annual production charges, a change in these costs would be significant. That is, if lease acquisition costs were to double in the future, or if twice as many lease blocks were required to find sufficient reserves, the unit production cost would then increase by nearly 65% as a result of the added lease costs, increased survey costs, and increased drilling costs.

8.1.2 Resource Use

In the broadest sense, resource use can be subdivided into mineral, land, air, water, manpower, and capital use. Capital resources have been discussed in the previous section and manpower resources will be summarized in the discussion on socioeconomic impacts. The following discussion relates to the natural resources -- minerals, land, air, and water.

Minerals. Because of the very diversified nature of the alternative high-Btu gas supply systems assessed in this study, mineral resource use is difficult to compare on a consistent basis. For example, one option consumes domestic natural gas reserves, another impacts foreign gas reserves, and the others consume different ranks of domestic coal reserves. A systematic scheme for comparing the relative impacts on mineral resources is to compare the net

conversion efficiencies of each gas supply option. For this purpose, net conversion efficiency is defined as the ratio between net energy output (including high-Btu gas and usable by-products) and total feedstock and fuel energy input during the operational phase of the system. Production efficiencies for foreign gas that is liquefied for exportation are not included; nor are other nonfuel inputs.

In order to compare the associated transmission pipelines, a transmission efficiency is defined as the net high-Btu gas energy delivered to the demand area divided by net high-Btu gas energy entering the pipeline at the exit gate of the production complex. Table 8.3 summarizes these efficiencies for the four supply options considered. System flow diagrams are presented in Appendix C.

The LNG importation system has the highest net conversion efficiency, with a terminal output totaling 87.06% of the gas loaded onto the transport vessels in Algerian ports. Offshore, lignite gasification, and bituminous gasification follow in succession with net conversion efficiencies of 71.66, 61.79 and 55.82%, respectively. It should be noted that the LNG system conversion efficiency is large primarily as a result of excluding foreign gas extraction and liquefaction from the efficiency definition. Had the production and liquefaction of the LNG been included, these process efficiencies would be about 70% each, which would result in a net conversion efficiency of about 43% -- much lower than that of any other option. Thus, if one is concerned with the efficient use of world resources, the LNG technology might not be an appropriate selection. On the other hand, it could be argued that these LNG supplies, if not consumed by the United States, would be used by other nations applying either the LNG or less efficient technologies, or wasted by flaring, thus affecting future society to at least the same degree.

Although the LNG technology is most efficient (within this study's definition), the offshore option would deliver more usable energy to the Chicago-Northern Indiana demand area, resulting from the greater heating value of the offshore gas. Although its conversion efficiency is over 15% lower than that of the LNG option, the offshore technology would ultimately supply about 1% more usable energy. Both of these options would supply 3-5% more energy than the coal gasification technologies. The difference between systems supplying the greatest and least amount of delivered energy is

Table 8.3. Net Conversion and Transportation Energy Balances and Efficiencies

Technology	Offshore Gulf of Mexico		Liquefied Natural Gas Importation		North Dakota Lignite Gasification		Southern Illinois Bituminous Gasification	
Product Gas Heating Value	1024 Btu/cf		1015 Btu/cf		970 Btu/cf		970 Btu/cf	
Energy Inputs: (10^9 Btu/day)	Gross Withdrawals	399.55	Net Exported	275.46	Gasifier Feed	354.64	Gasifier Feed	370.92
	Aux. Fuel	-	Aux. Vessel Fuel	16.00	Aux. Boiler Feed	102.85	Aux. Boiler Feed	122.54
	Total	399.55	Total	291.46	Total	457.49	Total	493.46
Plant Consumption: (10^9 Btu/day)	Vented, Flared, or Lost	2.18	Aux. Vessel Fuel	16.00	Aux. Boiler Fuel	120.85	Aux. Boiler Fuel	122.54
	Lease Property Fuel	12.69	LNG as Vessel Fuel	15.20		-		-
	Processing Plant Fuel	8.36	Plant Fuel	6.51		-		-
	Total	23.23	Total	37.71	Total	120.85	Total	122.54
Energy Outputs: (10^9 Btu/day)	High-Btu Gas	256.00	High-Btu Gas	253.75	High-Btu Gas	242.50	High-Btu Gas	242.50
	Fuel By-Products	30.32	Fuel By-Products	-	Fuel By-Products	41.40	Fuel By-Products	32.97
	Total	286.32	Total	253.75	Total	283.90	Total	275.47
Pipeline Consumption (10^9 Btu/day)	Fuel Use	3.48	Fuel Use	3.48	Fuel Use	3.48	Fuel Use	-
	Losses	2.26	Losses	2.24	Losses	2.14	Losses	0.43
	Total	5.74	Total	5.72	Total	5.62	Total	0.43
High-Btu Gas Delivered (10^9 Btu/day)		250.26		248.03		236.88		242.07
Net Conversion Efficiency		71.66%		87.06%		61.79%		55.82%
Transmission Efficiency		97.76%		97.75%		97.68%		99.92%

13.38×10^9 Btu/day; this amount of energy would be sufficient to satisfy the requirements of over 28,000 residential customers in the Chicago-Northern Indiana area.

Another consideration is important when comparing alternative systems that consume a variety of natural resources. Obviously, the high-Btu gas is the desired social benefit. This benefit might be derived from various feedstocks, depending on the technological option. That is, high-Btu gas can be extracted directly in that form (offshore option) or imported (LNG option), or it may also be converted from lower quality domestic feedstocks (coal gasification). The effect on resource use, however, depends on the abundance of the feed material resource base and the desirability of that resource for other processes. Table 8.4 illustrates this point.

In Table 8.4, consumption of feed material has been normalized to the first 15 years of operation. This resource use is compared with the known reserve base from which it would be derived. The LNG option is compared with the world reserves of natural gas. Its use includes production and liquefaction of the product. Strictly speaking, the LNG reserve base lies outside the boundary defined for this study. The coal requirements for the two coal gasification systems are compared with total U.S. coal reserves and the offshore system is compared with known U.S. reserves of natural gas both on shore and off.

Table 8.4. Natural Resource Consumption for First Fifteen Years of Operation

Technology	15-yr Natural Resource Use	Proved Reserve Base	% of Proved Reserve Base
Offshore	1.56×10^{12}cu ft	228×10^{12}cu ft[a]	0.68
LNG	3.03×10^{12}cu ft	2253×10^{12}cu ft[b]	0.13
Lignite Gasification	183.63×10^6 tons	435.7×10^6 tons[c]	0.04
Bituminous Gasification	121.40×10^6 tons	435.7×10^6 tons[c]	0.03

[a]Proved domestic reserves of natural gas.

[b]Proved world reserves of natural gas.

[c]Proved domestic reserves of deep and surface minable coals and lignite.

Land Use. Land use is measured in three different units, depending upon the type of use being considered and the project phase during which the land is used. Typically, some amount of land is temporarily used during the development or construction phase and resorts back to other uses, or is assigned to other developments once the system of interest begins operation. A measure of temporary land use is generally given as the product of area used and time devoted to that use, and is measured in acre-years. Additionally, two types of land use may be exhibited during the operational phase. The first type is generally called permanent land use and is that fixed area which is devoted to the production site for the service life of the system. Permanent land use usually includes the production site and other right-of-way areas directly associated with the project facilities. These areas are measured in acres. The second operational phase land use type is classified as disturbed land use and is measured in acres per year. Disturbed land use is defined as the annual land requirement (excluding permanent land use) necessary to support production activities over the service life of the facility. Areas disturbed by surface mining activities on a yearly basis exemplify this type of land use. Table 8.5 summarizes the land use impacts for each of the technological options addressed in this study.

Table 8.5. Land Use Impacts for Alternative High-Btu Gas Supply Reference Systems

Technology	Offshore	LNG Importation	Lignite Gasification	Bituminous Gasification
Temporary (acre-yr)	5500	18,000[a]	10,000[b]	10,000[b]
Permanent (acre)	157	208	1500-2000	1500-2000
Disturbed (acre/yr)	0	0	350	585
Unreclaimed at one time (acre)	NA	NA	700	1170

NA - not applicable

[a]3,000 acres for each LNG vessel per year during construction.

[b]Maximum site size times construction period.

The differences in land use impacts are readily apparent. Each of the coal gasification technologies requires a permanent land use which is a factor of ten larger than either the offshore or LNG importation option. Additionally, the lignite and bituminous gasification systems would respectively disrupt 350 and 560 acres per year in surface mining activities. No additional land disturbance is associated with the other options.

Water. Water uses generally refer to consumptive uses of this resource. Water use impacts are summarized in Table 8.6. Again, the coal gasification options require three orders of magnitude more of this natural resource to sustain their operation.

8.1.3 Environmental Residuals

Environmental residuals can be subdivided into air, water, and land residuals. From a public health point of view, air residuals are of greatest concern, since these pollutants enter the human respiratory tract directly through inhalation. Water and land residuals are generally thought to pose a less direct threat to human health, for it is usually necessary for these pollutants to progress through the food chain before entering the human body.

Table 8.7 compares the environmental residuals for the four technologies addressed in this study. In terms of air and land residuals, the coal gasification technologies generally emit quantities that are orders of magnitude larger than the offshore or LNG importation options. Because of the formation water produced in its gas operations, the offshore technology has the greatest impact from disposal of dissolved solids. However, the organics and chemical oxygen demand for the bituminous coal gasification technology are larger. The lignite gasification system, on the other hand, has zero water residuals because onsite disposal is assumed.

Table 8.6. Water Use Impacts for Alternative High-Btu Gas Supply Reference Systems

Technology	Offshore	LNG Importation	Lignite Gasification	Bituminous Gasification
Consumptive Water Use (gal/day)	8,640	16,560	17,280,000	17,280,000

Table 8.7. Comparison of Alternative High-Btu Gas Supply System Environmental Residuals

Technology	Offshore Gulf of Mexico				Liquefied Natural Gas Importation				North Dakota Lignite Gasification				Southern Illinois Bituminous Gasification			
	Lease	Plant	Pipe-line	Total	Termi-nal	Ship	Pipe-line	Total	Plant	Mine	Pipe-line	Total	Plant	Mine	Pipe-line	Total
Air Residuals																
Particulates	31	22	9	62	13	22	9	44	2,583	304	9	2,896	1,802	228		2,030
NO_x	919	639	1,260	2,818	293	132	1,270	1,695	18,577	9,113	223	27,913	13,723	6,856		20,579
SO_x	1	1	(a)	2	11	29	2	42	15,478	668	4	16,150	24,546	503		25,049
Hydrocarbons	908	12,088	16,750	29,746	204	14	16,750	16,968	2,150	1,058	16,750	19,958	1,492	796	3,330	5,618
CO	246	172	159	577	47	12	160	219	5,285	5,470	55	10,810	3,214	4,116		7,330
H_2S	(a)	(a)	(a)	(a)	(a)	(a)	(a)	(a)	95		(a)	95	170		(a)	170
Aldehydes						1		1	7	184		191	5	138		143
NH_3									17			17	18			18
Fugitive Dust										2,248		2,248		1,637		1,637
Water Residuals																
Suspended Solids				45								0				43
Dissolved Solids				70,520								0				9,030
Organics				14				10				0				3,700
COD				175								0				21,330
BOD				107								0				
Land Residuals																
Solids				-				-				$1 \cdot 10^6$				$1 \cdot 10^6$
Sludges				135				72				60,845				44,625

(a) Less than 0.5 ton/year.

At least half of the NO_x emissions associated with the offshore and LNG options results from the transmission pipeline operation, assumed here as utilizing existing pipelines with a mix of turbine and engine compressor drives. The emissions of NO_x from the lignite gasification system pipeline are a factor of six lower due to the fact that gas turbine compressors were assumed. The Illinois bituminous gasification system does not require pipeline compressors. The majority of the NO_x emissions associated with coal gasification emanate from the plant and mine sites, whereas in the other technologies these emissions emanate from the plant sites and from five or so compressor stations along the pipeline route.

SO_x emissions are 400-600 or more times greater for the coal gasification options than for the offshore or LNG technologies. The greatest amount of SO_x emitted from the coal gasification systems is associated with the gasification plant operations and emanates from the flue gas desulfurization system and other stack gas cleaning operations. Natural gas extracted from under the Gulf of Mexico is classified as *sweet gas*, containing only very small amounts of sulfur; thus no sulfur removal or recovery is necessary. Imported LNG also does not require cleaning, as this activity is performed prior to liquefaction and export.

At least half of the hydrocarbon emissions resulting from each system are caused by pipeline losses. Much of this loss is in the form of methane, the major constitutent of natural or synthetic high-Btu gas. In addition to straight chain hydrocarbons, the coal gasification systems would emit polycyclic aromatic hydrocarbon compounds. Many of these compounds have demonstrated carcinogenic activity in lower life forms and are suspected to be carcinogenic to man. Tables 6.23 and 6.24 list many of these compounds that have been identified. Aromatic hydrocarbons are not associated with offshore or LNG gas supplies.

Particulate emissions from the coal gasification systems are about 50-60 times larger than from the other systems. This fact and the large quantities of ash remaining once gasification or combustion of coal has taken place result in the large land residuals associated with coal gasification.

It is helpful to put the alternative high-Btu gas supply system residuals in perspective. The delivery of 250 MMcf per day of high-Btu gas is roughly

equivalent to the daily output of three 1000-MW electrical power plants operating at full capacity. Table 8.8 summarizes the maximum emissions permitted for 3000 MW of electrical generation based on the EPA's New Source Performance Standards. It is noted that the emissions from the gas supply options are many times smaller than those based on NSPS from electrical generation.

A comparison of water residuals with NSPS has not been attempted because the NSPS for water emissions are written in terms of allowable concentrations for individual plant streams.

Various heavy metals are also emitted from the high-Btu gas supply reference systems. Their form and concentrations, however, are not known and thus quantification is not possible at this time. Some attention is given to trace elements within Section 8.2.

8.1.4 Occupational Health and Safety

Table 8.9 summarizes the injury and fatality rates estimated for each of the reference systems and their associated pipelines. As is apparent by these data, the North Dakota lignite gasification system has the greatest impact on occupational safety. A total of 5668 man-days of labor are estimated to be lost as a result of one year's operation of this system. The southern Illinois bituminous gasification system is second to the lignite system with 4694 man-days lost assignable to a single year's operation.

Each of the gasification systems cause the loss of at least three times more potential productive labor than either the offshore or LNG importation system. The reason for this difference is twofold. First, the coal gasification reference systems are highly labor intensive compared with the other

Table 8.8. Permissible Emissions from 3000 MW of Electrical Generation Based on NSPS (tons/yr)

Fuel	Coal	Oil	Gas
Particulates	12,800	12,800	12,800
SO_2	153,700	102,500	No Standard
NOx	89,700	38,434	25,600

Table 8.9. Summary of Occupational Injury and Fatality Rates

Reference System	Occupational Fatalities & Injuries			
Offshore:				
	Platform Operations	Processing Plant & Adm.	Pipeline	Total
Fatalities	0.169	0.014	0.012	0.195
Injuries	2.543	1.278	2.000	5.821
Man-days Lost	1384	125	199	1708
LNG Importation:				
	Three-Tanker Fleet	Regasification Plant	Pipeline	Total
Fatalities	0.080	0.005	0.012	0.097
Injuries	2.528	0.388	2.000	4.916
Man-days Lost	790	54	199	1043
Lignite Coal Gasification:				
	Surface Mine	Gasification Plant	Pipeline	Total
Fatalities	0.480	0.141	0.012	0.633
Injuries	17.516	9.549	2.000	29.065
Man-days Lost	4075	1394	199	5668
Bituminous Coal Gasification:				
	Surface Mine	Gasification Plant	Pipeline	Total
Fatalities	0.384	0.141	0.002	0.527
Injuries	14.013	9.549	0.410	23.972
Man-days Lost	3260	1394	40	4694

systems. During operation the NDL and SIB gasification systems would employ 1125 and 1050 persons, respectively. These figures compare to the employment of 147 and 129 persons for the offshore and LNG importation options.

Second, coal mining -- even surface coal mining -- has accident and fatality rates that are high relative to most other industries. The synergistic effects of both large employment and high accident rates thus result in a much higher occupational safety impact.

8.2 NONQUANTIFIABLE SOCIAL COSTS

Nonquantifiable social costs include all adverse impacts on society that, for one reason or another, elude quantification. Generally, those social impacts that are not quantifiable result from a deficiency of knowledge in the subject area or simply cannot be expressed in measureable terms. An example of the latter may be the cost to society of an increased dependence on foreign energy sources -- surely a social cost (or potential social cost), since the embargo of such supplies could drastically impact the national security.

Those nonquantifiable social costs that have been identified during the course of the assessment are discussed in this section. The topics considered are socioeconomic impacts, human health and safety, and other issues.

8.2.1 Socioeconomic Impacts

The technological options examined in this assessment are diverse in feedstock, process, labor requirement, and geographic location. Because of the labor and geographic diversities, each system might be expected to impact the socioeconomic structure of its host community in somewhat different ways and to different degrees.

Recent evidence suggests that when the availability of jobs created by an energy conversion facility that exceeds the supply of willing local workers, both in-migration and ancillary local economic activity are stimulated. In some cases, especially those in which this growth is large relative to previously existing economic activity and population, economic, social, and political institutions have been unable to expand rapidly enough to accommodate the increased need for local services. Under such circumstances, the expected living standards of both old and new residents are not satisfied, out-migration begins, and productivity declines due to labor turnover ensues.

However, in other cases the stimulus of new employment opportunities has an opposite effect. In areas subjected to development that provides new jobs for unemployed or underemployed members of the local labor force, the social and economic effects may be positive. In such instances, the cycle of out-migration and economic decline may effectively be reversed by the advent of energy development activities.

The nature and extent of social and economic effects is dependent upon a number of factors particular to both the type and size of the facility and the economic, demographic, and geographic characteristics of the site locale as well. The rate and magnitude of socioeconomic changes may be directly dependent upon the following:

1. Capital and manpower requirements of the alternative system,
2. Availability of local workers,
3. Size of the labor pool within commuting distance of the site,
4. Accessibility of public and private services, and
5. Adequacy and accessibility of available housing.

A complete assessment of socioeconomic impacts is necessarily site dependent, since each of the above-listed items varies significantly from one site to the next. It is possible, once a specific site is selected, to assess the impact on local social services resulting from population changes associated with the construction and operation of the energy facility. Yet, due to the generic nature of this assessment, detailed site analyses are not desired. Thus, the approach taken was to select and subject *typical* sites to analysis and to infer impacts from the results. A socioeconomic impact model developed at Argonne National Laboratory was used for this purpose.[1,2] Relative local population change and number of new jobs filled are used as indexes for the actual socioeconomic impacts. In general, if growth is large relative to preexisting social conditions, the socioeconomic infrastructure is unable to adapt quickly enough and the quality of social services declines. The magnitude of change may be somewhat dependent on policies available to handle growth.

The driving function for the socioeconomic impact model is the direct construction and operation labor requirements necessary to support each of the reference systems. The annual averaged requirements are summarized in Table 8.10. Also shown are locations for each reference system that are typical of the general areas where each might be located.

Separate analyses of Mercer and neighboring Dunn County in North Dakota indicate that these basically rural counties could expect rather severe socioeconomic impacts with the introduction of a 250 MMcfd coal gasification plant. With the inclusion of secondary and income-induced jobs, a typical

Table 8.10. Direct Labor Requirements and Representative Locations for High-Btu Supply Alternatives

Yr	Offshore (includes platforms)	LNG Importation Plant	LNG Importation Vessels	NDL Gasification	SIB Gasification
1	84	-	-	-	-
2	378	-	-	390	390
3	888	-	1000	1395	1395
4	942	150	2000	2275	2275
5	637	280	2000	2550	2550
6	245	70	1000	640	640
Operating Lifetime	147	30	99	1125	1035
Location:	St. Mary Parish, La. (Central Gulf)	Calcasieu and Orleans Parishes, La.		Mercer Co., N.D.	Fulton Co., Ill.

county population could grow by between 100 and 130% by the third year of the construction phase. This rapid increase in population and demand for social services and housing would most assuredly stress and adversely impact the existing socioeconomic systems in these areas. Figure 8.1 illustrates the expected growth pattern for a typical small, rural western county.

Analysis of the four reference options indicates that each of these would have a net socioeconomic benefit in their respective regions. Both the offshore and LNG options are assumed to be based in southern Louisiana along the Gulf coast. This area already has highly developed oil and gas production, petrochemical, and ship building industries. The populations in the coastal parishes are fairly sizable, and the additional jobs created by introduction of these energy technologies would aid in relieving some of the unemployment in these areas. Because almost all of the primary, secondary and income-induced jobs would be filled by local residents, no additional burden on social services would be experienced.

Fulton County, Illinois, also has a significant available work force and, although the direct labor requirement associated with a reference coal gasification system in this area is very similar to its North Dakota counterpart, a

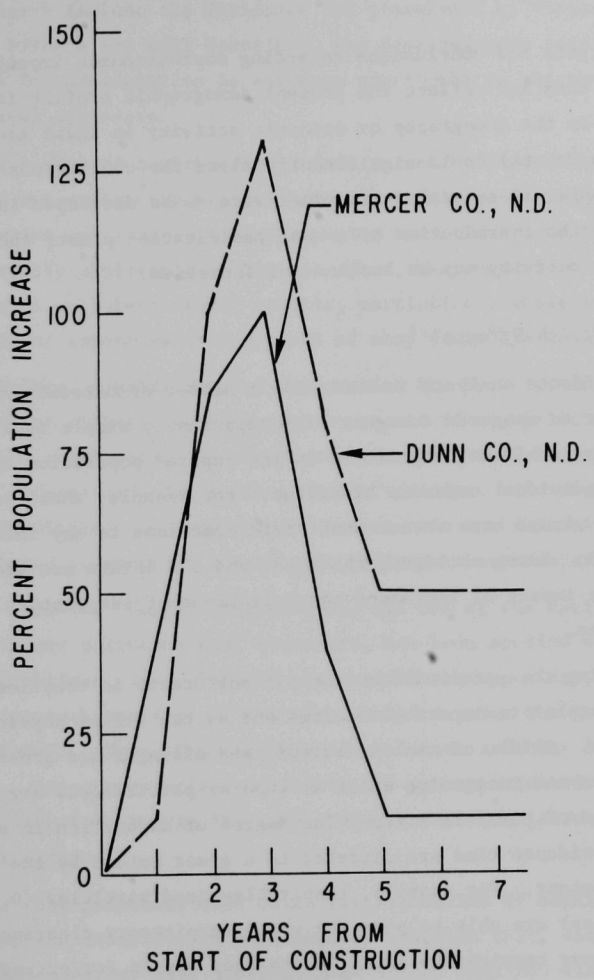

Fig. 8.1. Population Increases in Rural North Dakota Counties Due to Reference Coal Gasification System Construction

net socioeconomic benefit would be experienced. Local employment and income would expand along with an increase in basic economic activity, and local unemployed or underemployed residents who might otherwise leave the area would be retained.

The analysis and conclusions regarding socioeconomic impacts are based on 1970 census data and reflect the present demographic profile in each area. Future changes in the demography or economic activity in these areas (especially in North Dakota) could significantly alter the conclusions reached here. For example, if several strip mines were to be developed in Mercer County prior to the introduction of a coal gasification plant, the relative impacts of that activity may be lessened or increased.

8.2.2 Public Health Effects[4,5]

Health effects analysis is basically a matter of determining the biological response to measured dosages. This apparently simple task is complicated by the inevitable heterogenities in the exposed population coupled with variations in individual exposure histories. For example, there are some individuals who always have severe short-term reactions to any increased level of a contaminant. Young children, the aged, and the infirm are generally more sensitive to the impact of increased concentrations of respiratory irritants and other poisons.

Determining the received dose for air pollutants is complicated by the need to model complex transport mechanisms and by the varied physical forms of the effluents. Oxides of carbon, sulfur, and nitrogen are present as gases; volatile organics and inorganics exist as vapors; particulates are distributed over a wide range of particle sizes. The degree of deposition in sensitive areas and the residence time are dictated to a great extent by the physical form of the pollutant. For example, respirable-sized particles (0.01 to 1 micron in diameter) are able to pass the upper respiratory clearance mechanisms and enter the lower respiratory areas, where they remain for extended periods of time. Since they can absorb SO_2, and other irritant gases and vapors, their effect is magnified because of the fact that high concentrations of these irritants are held in proximity to sensitive tissues for protracted periods of time.

The measurement of biological response to a dose is difficult because the distinction between good and poor health is not sharp. Mortality is the index most commonly used because it is most easily measured. More useful but less available measures include the incidence and prevalence of disease. However, even when the effects are well described, the dose-response relationship may be obscure due to uncertainties in exposure conditions or the synergistic effect of several stressors.

A major source of health effects data is animal experimentation, for it can be carried out under controlled laboratory conditions. However, substantial uncertainties are related to interspecies variations, and the data are not always directly applicable to humans. Thus, many uncertainties remain in the prediction of pollutant health effects, particularly those for which chronic, low-level exposures over periods of many years are required.

Nevertheless, a great deal of information has been assembled on the known or suspected effects of the major components of air pollution resulting from hydrocarbon conversion. These effects generally fall into one or more of the following categories: irritation, direct toxicity, carcinogenesis, lung-clearance difficulties, and respiratory disease. In the following discussion, effects attributed to specific atmospheric pollutants are described.

Sulfur Dioxide. Sulfur dioxide (SO_2) was one of the earliest suspected toxic agents in air pollution and, therefore, has been studied extensively. In high concentrations, it is largely absorbed in the upper respiratory tract, but at low concentrations most of what is inhaled reaches the terminal bronchioles and alveoli. Thus, the effective dose is not a linear function of concentration. At concentrations of 0.3 to 1.5 ppm experienced in areas of heavy coal utilization, SO_2 in the pure state has not been shown to produce serious direct effects.

However, the potential does exist for irritation of sensitive tissues. Such irritation can stimulate an inflammatory reaction that, although basically a defensive response, may have a deleterious effect when too wide an area is involved. Realistic levels of SO_2 appear to cause a slight vasoconstriction lasting about 10-20 minutes in a previously unexposed subject, accompanied by a measureable reduction in lung elasticity lasting somewhat longer. Exposures lasting several days may cause slight changes in lung capacity, pulmonary

resistance, enzyme levels, and blood chemistry. In general, the irritant effect is mild for realistic dose ranges and tends to decrease with habituation.

Co-irritant effects have been observed in several cases. Prior exposure to SO_2 seems to increase the irritation resulting from ozone (O_3) and histamine. Conversely, a subject strongly habituated to SO_2 does not react as strongly to nitrogen dioxide (NO_2) as one without such prior exposure.

Carcinogenesis is one of the more difficult pollutant effects to quantify, since a long latent period may elapse before tumors develop. SO_2 has a potential for long-term carcinogenic effects through production of the SO_2 radical within cells. This is a relatively long-lived species with an affinity for breaking disulfide bonds and possibly causing gene mutations. The presence of SO_2 may also facilitate carcinogenesis by other agents such as benz(a)pyrene.

The presence of SO_2 may also enhance the effects of particulates by suppressing lung-clearing actions. Acute high-level doses suppress the activity of ciliated cells in the bronchial passages, and chronic low-level doses thicken the mucus layer over the cilia.

Nitrogen Oxides. Another pollutant that recently has been receiving greatly increased attention is the family of nitrogen oxides (NO_x). The two most important species are nitric oxide (NO) and nitrogen dioxide (NO_2). However, NO oxidizes rapidly to NO_2 so that the latter is the species most commonly found in the atmosphere.

Strong irritation is the most noticable effect of NO_2 exposure. Human experiments at moderate levels have shown evidence of inflammation, although the effects seem to be delayed several hours after the onset of exposure. Chronic exposures have produced irreversible emphysema-like lesions in experimental animals. A habituation effect has been noted, as with SO_2.

Carcinogenic effects arise from the formation in aqueous solution of the nitrite ion (NO_2), which, in turn, may contribute to formation of nitrosamines. As in the case of SO_2, co-carcinogenic effects with benz(a)pyrene have been observed.

Another similarity to SO_2 occurs in lung-clearance effects, since NO_2 also suppresses ciliary action in the bronchial passages.

Particulates. Particulates form a third component of air pollution that has received extensive attention. These products tend to have diameters in the 0.01-10-micron range, which places them directly in the size range for respirable particles. Deleterious health effects may be created by the action of the particles themselves or by absorbed gases and vapors carried by the particles to the point of deposition.

Particle size is a strong determining factor in several health effects. Those particles less than about 0.01 micron in diameter behave like gases and are generally not deposited at all. Particles with diameters between 0.01 and 1 micron deposit primarily in the alveolar or pulmonary region, whereas larger particles tend to deposit in the nasopharengeal and tracheobronchial regions. Chemical species contained in the particles also differ with size, with small particles generally being more toxic than large ones.

As noted previously, particulates may magnify the irritating effects of vapors and gases, such as SO_2, by holding high concentrations of an irritant ion, which is often associated with small particles, that appears to be a more potent irritant than any of the others discussed here. The potency is probably due to the very strong acid (H_2SO_4) that it forms.

Trace elements may also be carried by particulates. Nickel, chromium, beryllium and arsenic have been implicated as carcinogens. The known carcinogen, benz(a)pyrene, mentioned previously may be found in organic particulates associated with coal conversion. Direct disruption of cellular activity may be caused by such highly toxic elements as lead, tellurium, mercury, arsenic, selenium, chromium, and vanadium. Particles containing silica may induce various forms of fibrotic lung disease.

Other Pollutants. Several other components of air pollution have been recognized as having potentially harmful effects. These include carbon monoxide (CO), ozone (O_3), and hydrocarbons.

CO is best known for its hemoglobin affinity that results in the formation of carboxyhemoglobin (COHb). At COHb levels above 1.3% in the blood for over 8 hours, persons with stable coronary artery disease may note increased frequency and duration of symptoms. Effects at lower levels among healthy persons are not well defined.

Ozone is one of the stronger gaseous irritants. It also has been shown to be carcinogenic in certain strains of mice and to cause premature aging in some animals.

Hydrocarbon products of combustion are many and varied. Among them, formaldehyde and acrolein are recognized as irritants. Irritant reactions may be observed in the 1-3 ppm concentration range. Carcinogenic effects appear related to the polycyclic compounds such as those derived from the benz(a)anthracene skeleton. Identified carcinogenic compounds produced during coal gasification and combustion are presented in Table 6.23 and 6.24.

8.2.3 Other Nonquantifiable Costs

Trace Element Emissions. Non-airborne trace elements are a concern for the offshore drilling operations and the coal gasification technologies. During the development of offshore gas production sites, localized resuspension of bottom sediments can occur. These sediments may contain pollutants such as heavy metals and pesticides that have been deposited in the Gulf. The magnitude of the disturbance, however, depends on a number of variables, among them bottom type, currents, and duration of drilling activity.

During production from offshore reserves, toxic trace elements may also be discharged. These pollutants may exist as a result of the discharge of formation water, which is generally produced along with gas from the gas-bearing strata. In addition to heavy metals such as cadmium, chromium, copper, lead, mercury, nickel and zinc, these waters may also contain dissolved hydrocarbons and inorganic salts. The exact concentrations of these pollutants and their effects are dependent on various factors mentioned previously and may differ over the life of the gas production.

Because traces of heavy metals are also contained in coal, some release of these is anticipated to accompany coal gasification. Of particular importance are the elements of arsenic (AS), Mercury (Hg) and Lead (Pb), which are volatile and may be contained in the gaseous effluents from the plant. These elements may have the most direct deleterious effect on human health. At least 22 other trace elements are known to be contained in domestic coals. Some leave the production facility in the ash and others in the liquid effluent stream. However, the phase and ultimate fate of at least half of them is still unknown.

Lead, tellurium, mercury, selenium, nickel, chromium, and vanadium are all known to be highly toxic, with many exhibiting a special propensity for cellular deposition and retention. These elements are capable of interfering with and disrupting the function of the central nervous system and other organ systems of the body unrelated to the respiratory system. Table 6.25 summarizes the relative concentrations of trace elements in representative Central Interior and Northern Great Plains coals. As can be seen, those volatile and highly toxic elements previously mentioned are found in higher concentrations in the Central Interior coals. Thus, it might be concluded that the southern Illinois bituminous gasification reference system would have more of a harmful impact from trace elements than would the North Dakota Lignite System.

Offshore Hydrocarbon Spillage. Although the offshore production reference system has been assumed to produce nonassociated gas, the probability exists that in the experimental drilling connected with that discovery (or other activities) oil reservoirs may be encountered. Since nearly 12% of the proved gas reserves in the Gulf of Mexico are associated with oil, the potential of an oil spill during joint exploration or production must be recognized. The actual social cost resulting from such a spill might most justly be assigned to the cost of oil production, but since these activities are so closely related, consideration should be given to its potential.

LNG Hazards.[6,7,8] The hazards encountered in the transportation and handling of high-Btu gas in its gaseous state do not differ significantly among the four options considered in this assessment and are well understood. Its transportation and handling in the liquid state, as with the LNG technology option, poses several additional potential hazards that must be considered in the assessment of alternatives:

1. As a cryogenic liquid, LNG rapidly cools materials upon contact, causing extreme thermal stress on normal containment materials and, in the case of contact with humans, immediately freezes the skin.

2. LNG is a liquefied flammable gas that readily vaporizes when exposed to external heat sources (above 260°F), including water, soil, air, etc., producing approximately 625 cubic feet of natural gas vapor for each cubic foot of liquid. Unconfined, the vapor mixed with air is not explosive, but in a mixture of 5 to 15% vapor and air, it is highly flammable. Within enclosed spaces, if thus mixed with air in the presence of an ignition source, it can explode. The primary danger present

in a large-scale LNG spill is a very intense fire at the spill site; a more remote hazard is that the vapor plume could drift, into enclosed spaces and explode or catch fire. Once the air-vapor mixture has been ignited, fire will propagate back to the fuel source.

3. Methane is colorless, odorless, and tasteless and is classified as a simple asphyxiant, possessing only a slight inhalation hazard. However, methane or revaporized LNG, inhaled in significant quantities in time (i.e., exposure to a low oxygen concentration) would result in extreme health hazards including death.

Primary emphasis on LNG safety has centered on the analysis of public safety in the operation of LNG vessels in and around the near-shore shipping channels. The rationale is that shipping accidents are the most likely mechanisms for large-scale spillage of LNG. A land-based storage tank spill would probably be limited to the confines of the surrounding dike, thereby limiting the hazards associated with the event. Small LNG spills, such as truck leaks or flange and piping breaks, would also create hazardous situations but would be much less than those created by large-scale spills.

The marine transportation of LNG along near-shore shipping channels poses a threat to the public safety should an accident result in the spillage of LNG onto the water. In that case, the escaping LNG would vaporize and form a potentially flammable vapor cloud that could endanger the populace residing within the dispersion limits of the cloud. The direction of movement and the extent of travel of the vapor cloud would depend on the magnitude of the LNG spill, the prevailing meteorological conditions, and the number of nearby ignition sources. A shipping accident capable of releasing large quantities of LNG would be non-explosive and cause a sudden fracture of the ship's internal structure. This type of damage could occur as a result of collisions (ship to ship), rammings (ship to object), and groundings.

Ship collisions and groundings are considered the most likely causes of large-scale LNG releases, and the maximum credible accident is generally considered to be the instantaneous release of the contents of one storage tank (about 1/5 of the ship's cargo volume). Physical constraints on maximum vessel speeds and maximum depth of collision penetration render the possibility of a sudden LNG release of more than one cargo tank highly improbable. This is not to say that an accident involving a loaded LNG vessel and consequent loss of

its entire contents is not possible; but the occurrence of such a catastrophic event would require a fire and explosive forces and such ignition sources would preclude the formation of a hazardous LNG vapor cloud, which is the subject of major concern.

Obviously, the risk to the general public is dependent on many route-specific parameters, including population distribution along the transport route, shipping channel traffic density, channel width and depth, and shipping accident rates. Studies of ports that have been carried out in connection with specific proposals have defined two public risks of fatalities: those caused by a vapor cloud fire and those caused by heat radiation from an LNG pool fire. The range of probabilities associated with each risk is given in Table 8.11.

As with many recent accident probability studies, the analytical techniques, methodology, and underlying assumptions that make up these estimates have been criticized on many accounts. Opponents of LNG have called for increased research into the LNG-water reaction that has been observed to cause *minor* vapor explosions and for the siting of import terminals away from populated areas. The latter would be most difficult to achieve economically, because LNG tankers require deep water ports capable of handling vessel drafts up to about 40 feet. Existing deep water ports are generally engaged in various other importation activities and are thus the sites of relatively high population densities.

Table 8.11. Risk to General Public from LNG Transportation Activities

Incident (25,000 M^3_ℓ Spill)	Probability of Fatality (Per exposed persons/yr)
Vapor Cloud Fire	10^{-6} to 10^{-8}
Pool Fire Thermal Radiation	10^{-4} to 10^{-7}

Sources:

1. U.S. Federal Power Commission, FEIS for the Construction and Operation of an LNG Import Terminal at Everett, Mass. (Sept. 1976).
2. U.S. Federal Power Commission, FEIS Calcasieu LNG Project (Sept. 1976).
3. U.S. Federal Power Commission, DEIS for the Construction and Operation of an LNG Import Terminal at Providence, R. I. (Oct. 1973)

Reliance on Foreign Energy Supplies. Since the oil embargo of 1973-74, policymakers and others have become extremely skeptical of any increased reliance on foreign energy supplies. The LNG option is the only gas supply technology that would increase our nation's reliance on foreign sources of energy. Recognizing this, the Ford Administration's Energy Resource Council (ERC) recommended that U.S. imports of liquefied natural gas be limited to 2 trillion cubic feet per year, and that not more than 800 billion to 1 trillion cubic feet per year be imported from any single country for *national security reasons.*[9,10]

The Energy Resource Council concluded that the risk of LNG supply disruption warranted government action and noted that an LNG embargo would be easier to target against one particular country than would an oil embargo. However, the Council did admit that in some countries, financial needs make it difficult to sustain an LNG embargo over a long period.

Others, particularly the gas industry,[11] contend that the embargo would be difficult to execute for the reason noted by the ERC and also because current LNG projects match import and export terminals. An embargo against any one country, then, would directly impact each of their associated export terminals.

Though the relative magnitude of a potential embargo threat may be argued, it is clear that some possibility of supply diruption for other than technical reasons exists. If an embargo were levied against the United States, its impact would be determined by the amount of overall dependence on LNG, the time-of-year demand for gas, and the level of contingency within the domestic gas supply system.

8.3 DIRECTIONS FOR FUTURE ASSESSMENTS

This assessment compares alternative high-Btu gas supply options for a representative Midwestern area in the 1985-1990 time period. As previously noted, the technology options and sites were selected to provide specific reference conditions for impact evaluation. Structured information on social costs is provided under these conditions. The assumption of different reference conditions would alter this evaluation and thus require additional analysis. The extent of additional analysis is dependent on the nature of the assumptions.

This assessment provides a solid starting point for future gas supply and consumption evaluations. These may take any of a number of possible directions, the most notable including evaluations of:

- Higher-order impacts, and impacts in more detail and under different assumed conditions,
- Nonconventional gas resources (i.e., geopressured reserves, Devonian shales, tight sands and coal seams),
- Additional gas supply technologies (e.g., other coal and light oil gasification, SNG from biomass and municipal wastes, etc.),
- Other consumption regions,
- Large-scale implementation of advanced gas supply technologies or new gas sources,
- Conditions and impacts for low-Btu versus high-Btu gasification for limited applications,
- A gas versus a non-gas technology implementation in specified supply areas, and
- Gas supply, use and conservation policies where regional issues may hinder options.

Combinations of these items or additions to this list of possible future directions in social cost evaluations are easily envisioned.

The emphasis of future social cost assessments will vary depending on the areas of interest and information needs of the users. Whereas this initial study was conducted with broad perspective toward impact quantification and comparison, future assessments may emphasize and focus on a more limited set of issues and questions of interest to the user and decision maker.

8.4 REFERENCES

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APPENDIX A

FEDERAL REGULATIONS AND CONTROLS AFFECTING HIGH-BTU GAS SUPPLY[1]

A.1 DEPARTMENT OF THE INTERIOR

The influence of the Department of the Interior on the supply of natural gas is derived from the Mineral Lands Leasing Act of 1920 and the Outer Continental Shelf (OCS) Lands Act of 1953. The Mineral Lands Act granted authority to that department to lease publicly owned, onshore areas for the development of surface or underlying natural resources. The OCS Lands Act, on the other hand, charged the Secretary of the Interior with responsibility for the administration of minerals exploration and development on that portion of the continental shelf under federal jurisdiction. Those areas under federal jurisdiction had been defined by the Submerged Lands Act, also enacted in 1953, which gave coastal states jurisdiction over such lands to a distance of three miles or the boundary that had previously been approved by Congress. The two exceptions to the three-mile limit are Texas and the Gulf Coast of Florida, whose jurisdictional area extends for three leagues or nine miles from shore.

Within the Department of the Interior, the Bureau of Land Management is responsible for the leasing of public lands, and the Geological Survey regulates operating and production practices once the property is leased. The Geological Survey is also responsible for geophysical exploration of the OCS lands. Information provided by the Survey to the Bureau, along with other information, is evaluated prior to leasing to identify possible lease acreage and appraise potential resources. For the most part, the Survey purchases its geophysical data from private surveyors.

The Interior's basic objectives are, with respect to leasing and management of publicly owned mineral resources, to assure a fair market value return on the disposition of public resources and to protect the environment.

Under the Mineral Lands Act of 1920, leases are granted both by competitive bidding and by a simultaneous filing system. In the latter case, when a number of applications for the same lease are filed simultaneously, the right to priority is resolved in a public drawing. When land is within the known geologic structure of a producing field, however, it may be leased only by competive bidding and only in units of not more than 640 acres to the qualified

individual offering the highest lease bonus. If paying quantities of hydrocarbons are produced, a royalty of 12.5% of the gross revenues received from the property is charged.

Under the OCS Land Act, oil and gas leases are issued only on a competitive bidding basis. The present system involves cash bonus bidding by sealed bids accompanied by a certified check for 20% of the bid being offered.

The acreage of a single lease block may not exceed 5760 acres, and leases are issued for an initial period of five years but may be held thereafter as long as oil or gas is produced in paying quantities. Often, however, after discovery of oil or gas, the operator is not able to build and install facilities and lines to make the lease productive within the five-year limit. Although lease operators traditionally had been permitted an extension of their lease with little question, the Geological Survey has recently tightened its regulations. The conditions for nonproducing lease extensions now require that the operator be waiting for one or more of the following:

1. Platform or other production equipment,
2. Governmental permit,
3. Development plan or utilization agreement,
4. Completion of drilling program,
5. Development of special production equipment (deep water),
6. Pipeline construction, or
7. Pipeline use permission from another operator.

These more restrictive conditions are aimed at promoting a greater diligence in the development and production of federal leases in light of increasing natural gas shortages.

Although the 1953 Act specifies that a royalty of not less than 12.5% of the gross revenues be paid to the government once the lease is producing all OCS leases have required in actual practice a royalty rate of 16.7%. An annual rental is also set at $3 per acre for leases offered in general lease sales (unproven areas) and $10 per acre for leases obtained in drainage sales (proven areas). Since the passage of the Act, the Bureau of Land Management has conducted 41 offshore oil and gas lease sales. These sales have leased 13.7 million acres or 2% of a total 682 million acres of federally controlled OCS lands. Future OCS leasing plans call for a total of 23 leases during 1977 through 1980 covering nearly all of the United States OCS regions.

Opposition has been encountered in the first OCS lease sale in the Atlantic held on August 17, 1976. In a recent decision, the Federal District Court at Brooklyn ruled in favor of the State of New York declaring the sale of nearly 530,000 acres off the mid-Atlantic coast null and void for failure of the Department of the Interior to adequately consider, under the provisions of NEPA, the impact of the sale on adjacent shoreline states.[3] And a previous sale, originally set for December 1971 in the Gulf of Mexico, was blocked by environmental groups who claimed that the Department of the Interior did not comply with NEPA by failing to adequately discuss alternative actions to the sale. After issuance of a supplement to the Environmental Impact Statement, the sale was held in September 1972.

Opposition to federal OCS lease sales by environmental groups and adjacent states poses what is perhaps the major roadblock to further development of the OCS. This reaction will prevail particularly in areas not already developing oil and gas reserves and in environmentally sensitive areas such as those off the coast of Alaska.

A.2 DEPARTMENTS OF STATE, DEFENSE, AND COMMERCE

The Departments of State and Defense both have an important voice in policy matters affecting the supply of petroleum in the United States. In the past, the activities of these departments have been directed largely to oil. But, in view of the probability of increasing imports of gas (and liquid feedstocks for the manufacture of gas), the degree of interfuel substitutability possible in many markets and the need for a coordinated interfuel approach to current energy questions, they both seem likely to become increasingly active in the formation of policies affecting the supply of natural gas in the future.

To date, they consistently have been asked by the Federal Power Commission for their position on pipeline imports from Canada and Mexico, and, more recently, on liquefied natural gas imports from African nations as well. Under Executive order, the FPC is required to obtain the favorable recommendation of the Departments of State and Defense for the construction of facilities for exportation and importation of gas.

Thus far the State Department has not opposed any announced gas imports, nor has the Defense Department recommended denial of any such project. The

Defense Department has expressed concern in some instances, however, that individual pipelines and gas distribution companies not become overly dependent on imported LNG.

Similarly, the Commerce Department has not played a significant role in policies affecting gas supply in the past. Yet, it is worth noting that during 1972 the department participated in trade negotiations with the Soviet Union, involving, among other things, the possibility of a joint venture to bring Soviet gas in liquefied form to the United States. Shortly thereafter, the department indicated that an early agreement concerning such a venture was not imminent. Even if some form of tentative agreement were signed in the future, the importation of Soviet LNG would face numerous other policy and regulatory constraints.

A.3 FEDERAL POWER COMMISSION

Without a doubt, the federal agency with the most widespread authority regarding natural gas and natural gas supply is the Federal Power Commission (FPC). The FPC has extensive powers to regulate the transportation and sale for resale of natural gas in interstate commerce. These regulatory powers, vested in the FPC, stem from the Natural Gas Act of 1938, but were broadened considerably by the Supreme Court's ruling in the *Phillips Petroleum Company v. State of Wisconsin* case of 1954.

A.3.1 Background to the Natural Gas Act

Passage of the Natural Gas Act resulted largely because of pressures arising from diminishing gas production in the Appalachian region after 1917 and the inability of particular states to control sharply increasing prices on gas imported from other states. In 1928, the Senate directed the Federal Trade Commission (FTC) to investigate public utility corporations selling electricity and natural gas in the interstate market, as well as the activities of holding companies that controlled such corporations. In 1935, seven years later, the FTC issued a report outlining the problems created by the unregulated control of pipeline transmission, the concentration of control of interstate pipelines in a few holding companies, and the need for conservation of natural gas. The principal conclusion of the report was that the business of transporting and selling natural gas for ultimate distribution was a matter of public

interest and should be subjected to federal regulation. It was largely on the basis of the FTC report that Congress passed the Natural Gas Act three years later.

At the time of enactment, the Natural Gas Act was widely thought to apply only to interstate pipelines. The legislative history gave no indication of any intent that it also covered independent producers. This interpretation was also believed to be derived from a specific statement in the Act:

> The provisions of this act shall apply to the transportation of natural gas in the interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.

This provision proved to be ambiguous and a source of considerable controversy over the next fifteen years. During this time the FPC consistently declined to assume jurisdiction over the sale of natural gas by producers, except those affiliated with interstate pipelines.

In 1951, following an investigation to determine whether the Phillips Petroleum Company was a natural gas company subject to its jurisdiction, the FPC reaffirmed its position that producer sales were so closely related to *production and gathering* as to be exempt from federal regulation. This decision was reversed by the U.S. Court of Appeals, and was subsequently upheld by the Supreme Court. In 1954 the Court interpreted the section of the Natural Gas Act exempting production and gathering to mean the *physical activities, facilities, and properties used in the production and gathering of gas,* but not the sales after production and gathering. Rather, the Court concluded that *the legislative history indicates a congressional intent to give the Commission jurisdiction over the rates of all wholesale of natural gas in interstate commerce, whether by a pipeline company or not and whether occurring before, during, or after transmission by an interstate pipeline company.*

Thus, FPC jurisdiction over wellhead sales by independent producers for resale in interstate commerce was established. Although various legislative efforts were made in the next few years to remove this jurisdiction or to

lessen the extent of the FPC's authority over independent producers, none were successful.

A.3.2 Producer Rate Regulation

Subsequent to the Supreme Court's ruling in 1954, the regulation of interstate natural gas at the wellhead has been a dominant factor affecting its supply. Since that time the FPC has attempted various methods to regulate the sale of natural gas at the wellhead, the end result of which has been to hold gas prices at an artificially low level, discouraging additional investment by gas producers and increasing the demand in all sectors of society.

Producer rate regulation can be conveniently described in four chronological periods: 1954-1960, 1961-1968, 1969-1974, 1974-date.

A.3.2.1 Period 1954-1960

Two major tasks are involved in the regulation of wellhead gas prices--the certification of new producer sales and the approval of existing producer rate increase applications. With respect to the certification of producer sales in this early period, the Commission generally approved the prices contained in the contracts. This practice was ended in 1959 with a Supreme Court decision in a case involving the sale of large volumes of gas by a group of four producing companies. The sale price in dispute was the highest ever negotiated at the time and after twice refusing to certificate the sale, and faced with the threat of contract cancellation and dedication to intrastate markets, the Commission granted its approval. The Supreme Court reversed this approval holding that the Commission was obligated to attach conditions to prices deemed *out of line* or otherwise not in the public interest. The Court said:

> Where the proposed price is not in keeping with the public interest because it is out of line or because its approval might result in a triggering of general price rises or an increase in the applicant's existing rates by reason of 'favored nation' clauses or otherwise ... the Commission in the exercise of its discretion might attach such conditions as it believes necessary.

Also during this period the FPC attempted to regulate the many existing gas producers on an individual basis using a cost of service approach, the same approach that is customarily used to determine electric utility and gas transmission rates. In these proceedings, the Commission consolidated each company's

rate increase applications and investigated them relative to the company's cost of service. These proceedings proved to be exceedingly complex and time consuming, primarily because of the difficulties in attempting to adapt the cost of service method to regulation of producers. By 1960 only 11 such cases had been decided, while 3278 producer rate increase filings involving 570 companies were awaiting hearing and decision.

The FPC concluded, on the basis of its experience up to that time, that the traditional original cost, prudent investment-rate-base method of regulating utilities is not a sensible or even a workable method of fixing the rates of independent producers of natural gas. The Commission pointed out that producers, for whom the results of exploration are highly uncertain, are not like public utilities that have a reasonably predictable relationship between investment and output. Further, the necessity of allocating joint costs (that is, costs incurred in producing oil and gas jointly) between gas and oil greatly complicated the costing process and led to widely divergent results, depending on the allocation methods used.

For these reasons, the FPC declared its intention to henceforth determine producer rates for the industry on an area basis. Simultaneously the Commission established two sets of guideline prices for 23 different producing areas -- one set applicable to initial prices for new sales, and the other applicable to increased rates for existing sales. These guidelines did not constitute determinations of just and reasonable rates but rather were intended to facilitate producer regulation during the interim pending the completion of area rate proceedings. In some areas, the new sale guideline rates were well below previously authorized sales; the guideline levels for rate increase purposes were even lower.

A.3.2.2 Period 1961-1968

This period of FPC regulation was dominated by the area rate hearings, of which only two were completed. These two cases established rates for the Permian Basin area at a level slightly higher than the 1960 guidelines and established rates for the South Louisiana area at a level lower than the guidelines.

The evidence introduced at these hearings included supply-demand trends, exploration efforts, pricing history, and financial requirements. The evidence

was not related to particular companies, but was computed on national and area bases. Even with the outlawing of evidence pertaining to individual companies, these hearings stretched out over a period of years and produced a total of nearly 65,000 pages of transcript.

The resulting decisions on the two completed cases established a two-price system in each area with a higher price ceiling on new gas intended to encourage exploration of new gas reserves and a lower ceiling on *flowing* gas for which investments had already been made. The area rate rulings were challenged in the U.S. Court of Appeals but upheld. The Court, however, expressed *serious misgivings* as to the adequacy of the Commission's findings regarding supply, demand, and the impact of the prescribed rates.

The 1961-1968 period was also dominated by a series of new gas certificate proceedings in which the Commission established (pending area rate decisions) *in-line* prices at or below the guideline prices set in 1960.

In the certificate proceedings, the Commission examined the prices at which sales in the area had previously been certified, excluding those certificates that were under court review, and then selected the in-line price level from the remaining sales. The overall effect of the exclusion was the consideration of a range of new price applications that did not include the higher prices and that had been applied for but denied by the Commission.

Nearly all of the FPC's in-line price decisions were attacked on multiple grounds in the courts. The main issues concerned the prices which the Commission should take into account in the proceedings, whether the FPC could prohibit producers from increasing rates above levels that would trigger widespread increases in the areas involved, and the extension of the Commission's authority to order refunds of amounts collected above the in-line rates under both judicially invalidated and temporary certificates.

The Supreme Court upheld the FPC's methods in all respects, and in particular the Court ruled that the imposition of maximum price levels below specified *triggering* levels was a justifiable means to keep the general price of gas relatively constant during the determination of just and reasonable rates, and that the Commission could order refunds of amounts collected in excess of in-line rates under temporary certificates that did not include an expressed refund condition.

The Court's ruling on this last issue is of particular interest in terms of its effect on producer expectations. The FPC first ruled that it would not be equitable to require refunds in such situations because the temporary certificates contained no explicit language to warn the producers of the possibility of a refund and because the imposition of a retroactive refund would so denature the value of the Commission authorization as to place reliance on its actions in this area in serious jeopardy. On appeal, however, the Circuit Court held that the FPC had power to order retroactive refunds and that the FPC should undertake a more penetrating analysis of the equities involved. This decision was also upheld by the Supreme Court, stating that when a producer requests permission to begin deliveries of gas prior to completion of normal certification procedures, it is not unfair, in return for that permission, to accept the risk that the conditions may be retroactively altered to conform to the public interest.

The net effect of this period was to hold producer gas prices at the preexisting or lower levels than were set during the earlier period.

A.3.2.3 Period 1969-1974

By late 1968, signs of a natural gas supply shortage were growing. Becoming aware of the supply problem, the FPC's regulation of producers increasingly shifted toward the adoption of corrective measures aimed at reversing the downward trends in gas supply and encouraging increased levels of exploration. The FPC stressed, among other things, the need of offering incentives to find and dedicate natural gas to the interstate market.

The Commission's more important rule-making actions in this area include: (1) exemption of sales by small producers (10 billion cubic feet per year) from nearly all regulation under the Natural Gas Act, (2) encouragement of pipeline companies to advance funds to producers to explore for and develop new gas supplies by permitting the inclusion of the advances in the pipelines rate bases, and (3) seeking to relieve curtailment problems for individual pipelines by permitting the purchase of gas on an emergency basis at rates higher than the area ceiling.

The U.S. Court of Appeals upheld the advancement of funds by pipelines to producers as a justifiable experiment in the FPC's search to alleviate

the gas shortage, but overturned the exemption of small producers from rate regulation, holding that this action was an abdication of the Commission's responsibility to insure that all rates are just and reasonable.

A.3.2.4 Period 1974-Date

In 1974, the FPC again changed its procedure for determining the acceptable sale price of natural gas by the producers. This time, however, the Commission declared its intention to determine the maximum wellhead sale price of gas on a national basis, largely eliminating the determination of rates on an area basis. The commission has since set the National rate of 52¢ Mcf and more recently at $1.42/Mcf for 1975-76 vintage gas and 93¢/Mcf for 1973-74 gas. The 1975-76 gas also carries a 4¢/Mcf annual escalation whereas the 1973-74 vintage escalates at 1¢/Mcf per year.[4] These prices compare to an average price of $1.58/Mcf on the intrastate market (which is not subject to FPC regulation) during the second quarter of 1976.[5] Many believe that these most recent rates have hindered congressional action that might have developed on the deregulation of natural gas for perhaps several years, as the new rates are appealed through FPC administrative and federal court channels.

The most recent proposal for natural gas pricing is contained in the Carter Administration's National Energy Plan (NEP). As proposed in April 1977, the NEP would change the natural gas pricing method from one based on historic production costs to a commodity value pricing approach that reflects the current costs and degree of risk associated with finding new gas supplies. Under the proposal, all new gas sold (intra- as well as inter-state) from new reservoirs would be subject to a price limitation at the Btu equivalent of the average refiner acquisition price of all domestic crude oil. That price would be approximately $1.75/Mcf. (Intrastate gas made available to interstate markets at the expiration of existing contracts would be treated as new gas.)

The proposed federal pricing policy would also discourage use of gas by industry and utilities. The wellhead cost of the more expensive new supplies would all be allocated initially to industrial users, not to residential and commerical users since they would have far less capacity than industrial consumers to convert to other fuels.

Finally, the higher price of synthetic gas would not be rolled in with the price of natural gas, but would also be initially allocated to industrial customers.

A.3.3 Pipeline Rates

Pipeline rates have been determined by the FPC from the outset by the traditional utility rate base method, which involves the calculation of a total cost of service for a specified test period and the translation of that cost of service into jurisdictional rates through various cost allocation and rate design techniques.

The costs to be recovered through rates include all operating and maintenance expenses, depreciation and depletion, and taxes, plus a fair return on the rate base. The rate base consists of investment of original costs less accrued depreciation plus an allowance for working capital. Determination of the rate of return is governed by the criteria that a fair return is commensurate with returns on investment in other enterprises with corresponding risks, sufficient to attract capital and adequate to assure financial integrity.

Use of the cost of service approach for determining pipeline rates is widely accepted, although the computation of individual cost components and the determination of the rate of return level are frequently heavily contested in pipeline rate proceedings. However, these disputed costing matters seldom have any bearing on whether more or less gas will be available for sale.

The one exception to this procedure relates to gas produced by a pipeline company or purchased from an affiliated producing company. Up until 1969 such companies were allowed to include in their cost of service an allowance no greater than the estimated cost of producing the gas. For most pipelines, such allowances were considerably lower than the prices paid to independent producers for gas purchases in the same producing areas.

In 1966, the FPC initiated proceedings to determine the proper method to be used for pricing gas produced by pipeline companies or obtained from affiliated companies. Evidence submitted in the proceedings indicated, among other things, that reserves owned by pipeline companies engaged in production operations declined both absolutely (30% between 1958-1966) and as a proportion of national gas reserves (25% to 13% over the same period).

In October 1969, the FPC responded by deciding that gas produced by pipelines from leases acquired thereafter could be reflected in the pipeline rates at the area price levels allowed to independent producers for comparable gas. This change to an area pricing method was intended to encourage pipelines to increase their search for and production of gas. Although the FPC was judicially affirmed in this new approach, no significant increases in pipeline-produced supplies have resulted.

A.3.4 Imports and Exports

Importation and exportation of gas from the United States requires FPC approval under Section 3 of the Natural Gas Act. During 1975 the United States exported 72,675 million cubic feet (MMcf) of gas and imported 965,008 MMcf. These totals represent 0.42 and 5.60% of the net marketed production during that year. These quantities include LNG exports to Japan of 53,000 MMcf and LNG imports of 4,893 MMcf. The remaining volumes are primarily in the form of overland pipeline exchanges with Canada and Mexico, although the American Gas Association reported no imports from Mexico during 1975.[6]

A.3.4.1 Canadian Gas

Canadian gas imported to the United States requires not only import authorization from the FPC but also export authorization from the Canadian National Energy Board (NEB). Authorization must also be obtained from the Alberta Energy Resources Conservation Board for the removal of gas from the Province of Alberta, the major producing region in Canada.

Pipeline imports from Canada commenced in the early 1950s but until 1958 were exceeded by exports. While different considerations were apparent on the two sides of the border, no serious conflict between the FPC and the NEB in regard to import-export policies developed until 1967. In that year, the two regulatory bodies were presented with a proposal involving an increase in U.S. imports at a price deemed out of line by the FPC who emphasized the importance of price as a prime consideration in certificating gas imports.

In response, the NEB announced three criteria for determining whether a proposed price for export of gas is in the Canadian public interest, namely, the price must (1) recover the appropriate share of costs incurred by the

Canadian transmission company, (2) not be less than the price to Canadian customers in the general area of the proposed export, and (3) approximate the least-cost alternative for energy from indigenous sources in the United States market area. The NEB also made clear its position that the so-called in-line pricing theory applied by the FPC for evaluating border prices was totally inconsistent with the Canadian public interest.

More recently, however, the price issue has assumed a secondary role with Canadian denial of several export licenses due to a lack of surplus gas. The NEB's current policy is to approve for export only those volumes determined to be in excess of the quantities required to meet the estimated level of Canadian consumption for 25 years. Since the Canadian government estimates an insufficient surplus, it has granted export request to only four existing transmission companies. These approvals were made with reduced terms and other conditions. All new requests have been rejected.

Although the NEB's surplus estimate did not account for reserves in Canadian frontier areas where a potential exists for relatively large reserves, additional large exports are not expected to be approved by the Canadian government in the future.

A.3.4.2 LNG Imports

Beginning in 1968, the Federal Power Commission has authorized several short-term imports of LNG. The FPC simply assumed jurisdiction in approving the various short-term projects, none of which were questioned by any party. In 1972, however, the Commission dealt with the question of ruling on two long-term LNG import proposals.

The first long-term project considered was a proposal by Distrigas Corporation to import the LNG equivalent of 15.4 bcf annually from Algeria over a 20-year period for peak shaving purposes. Upon approval of the project in March 1972, the Commission held that LNG is natural gas and is subject to its jurisdiction in the same manner as other natural gas. That is, the FPC declared its authority over the importation of LNG regardless of its uses thereafter. Also, a majority of the Commission concluded that it had authority over the transportation and sale for resale of LNG in interstate commerce. Because most of the LNG from this project was to be consumed in the states of importa-

tion, the Commission declined jurisdiction over its post-import transportation and sale.

Although the Commission assumed jurisdiction over the importation of LNG, it declined to take jurisdiction over all of the operations of Distrigas at the point of receipt in the United States (i.e., the ship's flange). The Commission chose not to do so because of a desire to encourage the development of new and supplemental sources of natural gas at least as long as these supplemental sources remained competitive with other available supplies of gas or alternative fuels.

Not all of the Commissioners agreed with these points. Two of the five Commissioners contended that the FPC should exercise comprehensive jurisdiction over LNG import projects, including the transportation, sale, and price of the delivered LNG whether or not it is sold in interstate commerce. These Commissioners further argued that the decision created a regulatory gap and in effect sanctioned a *what-the-traffic-will-bear* approach to prices, thereby ignoring both the impact on domestic gas supplies and the need to protect the ultimate consumers. It was contended also that this decision placed an impossible burden on state regulatory commissions and could encourage the emergence of a vast network of unregulated intrastate distributors of LNG along the Atlantic Seaboard, contrary to the public interest.

The second major LNG project considered by the FPC in 1972 involved the importation of one billion cubic feet per day from Algeria to subsidiaries of three major interstate pipeline companies -- Columbia Gas Transmission Co., Consolidated Gas Supply Corp., and Southern Natural Gas Co. The proposal differed from that of Distrigas in two ways. First, the importing companies planned to use the LNG as a supplement to their baseload services, and, second, a significant amount of the imported LNG was to be transported and sold in interstate commerce.

This second proposal was approved unanimously in June 1972. However, the Commission attached several unexpected and controversial conditions. Four of these conditions are of particular interest:

1. The FPC directed the three importing companies to sell the regasified LNG to their customers at incremental rates rather than at rolled-in rates as had been proposed. The Commission reasoned that rolled-in pricing of the more expensive LNG

would disguise its true economic cost. Moreover, to assure that incremental LNG prices would be passed through to the customers, the FPC prohibited the importing pipelines from selling to distributors who did not have separate rate schedules for reselling the LNG at incremental rates.

2. The FPC imposed a fixed limit on the import prices to be paid by the importer. By this condition, the Commission prohibited the operation of cost escalation provisions in the contract designed to protect the importer against inflationary cost increases over the contract term. The FPC set the price ceiling at the level of estimated delivered LNG costs in the first full year of deliveries, and said indefinite escalation in costs to consumers should not be permitted.

3. The FPC specified that if, at any time, more attractive supply sources for the interstate market became available, the terms upon which the imported LNG will be authorized for the interstate market may be adjusted accordingly.

4. The FPC outlawed provisions for the recovery of project costs in the event of an interruption in the LNG supply.

Faced with opposition and possible cancellation of the project, the FPC modified its decision in October 1972. The modifications conceded to were allowed as necessary to assure financing of the project. Specifically, the Commission retained the requirement that the importing pipelines sell LNG on an incremental basis, but eliminated the further provision requiring distributors also to sell on that basis. The Commission retained the fixed import price ceiling, but indicated price adjustments would be allowed for additional costs shown to be justified. They also clarified the language referring to the possible adjustment of imported LNG if more attractive alternative supplies became available, stating that it did not indicate an intent to alter the terms of the project but was meant to apply to consideration of future projects. And finally, the FPC relaxed the prohibition against the recovery of project costs in the event of a supply interruption so as to permit the recovery of out-of-pocket expenses but not depreciation or return on investment.

In a more recent related decision, the FPC reversed its 1972 ruling on incremental pricing. In January 1977 the Commission stated that due to the current high price permitted on domestic gas and because the price is competitive with the estimated costs of imported LNG, the LNG should no longer be viewed as an *expensive exotic supply*. The Commission has thus allowed the three importation pipelines to sell LNG at rolled-in prices. The

Commission further stated that the pricing issue is much too complex to be resolved for all future supplemental supply projects.[7]

A.3.5 Gasified Coal

FPC regulation of synthetic gas (SNG) produced from coal has raised many of the same questions as has the importation of LNG. Today, the FPC requires certification of coal gasification projects and their associated pipelines if the product gas is to be distributed in the interstate market. And, although it now requires incremental pricing, this ruling is based on the fact that gasified coal is estimated to cost significantly more than the price allowed for domestic natural gas. However, if these costs were to become competitive, it is probable that the Commission would reconsider its policy as was recently done for the LNG proposal previously cited.

A.4 REFERENCES

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3. Department of the Interior, personal communication (Feb. 14, 1977).

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APPENDIX B

HISTORIC AND FUTURE TRENDS REGARDING NATURAL GAS RESOURCES, PRODUCTION, AND USE

B.1 HISTORIC TRENDS

The statistical information presented here intends to provide both historical and present perspectives regarding domestic and world natural gas resources, production, and use. These data are also provided as a means of framing the social cost assessment within an overall view of the natural gas industry, and to assist the reader in interpreting definitions and relative magnitudes of physical quantities (e.g., natural gas volumes), which are referred to throughout the report.

B.1.1 Natural Gas Resources

The term *resource* as defined by the U.S. Geological Survey (USGS) and U.S. Bureau of Mines (BOM) means "concentrations of naturally occurring solid, liquid, or gaseous materials in or on the earth's crust in such form that economic extraction of a commodity is currently or potentially feasible." Within this broad definition are several subclassifications that are identified and defined in terms of degree of geologic assurance and economic feasibility.[1] Definitions for each of the classifications are given in Table B.1. Figure B.1 is a diagrammatic representation of the resource subclassification structure for domestic natural gas. Figure B.1 also shows the quantities (tcf) of natural gas included in each subclassification as of December 31, 1974.

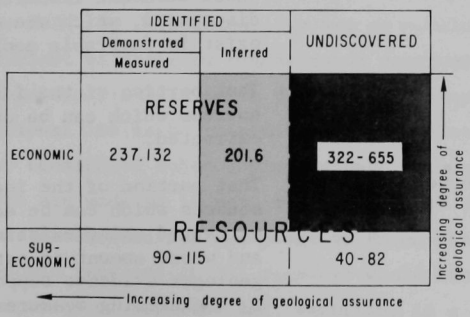


Fig. B.1. USGS and BOM Resource Classification System

Table B.1. USGS and BOM Resource Classification Terminology

Terminology	Definition
Resources	Concentrations of naturally occurring solid, liquid, or gaseous materials in or on the earth's crust in such form that economic extraction of a commodity is currently or potentially feasible.
Economic Resources	Those resources, both identified and undiscovered, which are estimated to be economically recoverable.
Subeconomic Resources	Identified and undiscovered resources that are not presently recoverable because of technological and economic factors but which may be recoverable in the future.
Identified Resources	Specific accumulations of economic resources whose location, quality and quantity are estimated from geological evidence supported in part by engineering measurements.
Undiscovered Resources	Quantities of a resource estimated to exist outside of known fields on the basis of broad geologic knowledge and theory.
Undiscovered Recoverable Resources	Those economic resources, yet undiscovered, which are estimated to exist in favorable geologic settings.
Reserves	That portion of the identified resources which can be economically extracted.
Measured Reserves	That portion of the identified resources which can be economically extracted using existing technology and whose amount is estimated from geologic evidence supported directly by engineering measurements. (Equivalent to API & AGA Proved Reserves and include underground storage).

Table B.1 (Cont'd)

Terminology	Definition
Demonstrated Reserves	A collective term for the sum of measured and indicated reserves.
Inferred Reserves	Reserves in addition to demonstrated reserves eventually to be added to known fields through extension, revisions, and new finds.

Source: U.S. Geological Survey, *Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States*, pp. 8-9, 34.

As of December 31, 1974, domestic demonstrated gas reserves* were estimated at 237.1 trillion cubic feet (tcf), inferred reserves at 201.6 tcf, and undiscovered recoverable resources at between 322 and 655 tcf. The range of undiscovered recoverable resources corresponds to a 95% probability that the lower value and a 5% probability that the upper value is yet undiscovered. The mean value of undiscovered recoverable resources was estimated at 484 tcf.

The Geological Survey has also made estimates of subeconomic domestic natural gas resources. Subeconomic identified resources of natural gas were approximated in the following manner: First, it was assumed that 80% of the original gas-in-place (which includes cumulative production) is recoverable if there are no substantial changes in present economic relationships and production technology. Secondly, the current 80% recovery factor could ultimately increase to 90%. By definition, the sum of cumulative production to date, plus the current estimate of demonstrated reserves, accounts for 80% of the original gas-in-place in known fields; an increase to 90% recovery would allow an additional 10% to be recovered. As indicated in Fig. B.1, the extra 10%, presently considered subeconomic, amounts to approximately 90 tcf. The inferred reserves are made up in part of revisions of current estimates and in part of future extensions and new pools in known fields. The 201.6 tcf of inferred economic reserves at 80% recovery would have associated with it a noneconomic component of about 25 tcf, resulting in a range of subeconomic

*Identical to American Gas Association's Proved Reserves Classification.

identified reserves of between 90 and 115 tcf. Similarly, the subeconomic component of undiscovered gas resources was estimated to include 40-82 tcf.

During 1975 demonstrated reserves were altered downward by 8.93 trillion cubic feet (tcf) with the addition of 10.78 tcf and a net production of 19.83 tcf, resulting in a December 31, 1975, demonstrated reserve base of 228.2 tcf. Table B.2 outlines the geographical distribution and reserve type of all demonstrated domestic reserves. Note that 68.7% of the 1975 year-end reserves were from nonassociated reservoirs. Reserves associated with or dissolved in oil composed 29.4% of the total, and underground storage added another 1.9%.

In a review of domestic natural gas reserves, it is instructive to note the historical trends relating annual net production with annual reserve additions and proved recoverable reserves. Before 1967, reserve additions were able to keep pace with and exceed net productions. This trend reversed in 1968 with net production exceeding reserve additions by a substantial margin for the first time in domestic gas production history. With the exception of 1970, the period of 1968 through 1975 has shown annual reserve additions at only about half the annual net production rate. The 1970 reserve additions exceeded production of that year largely as a result of the addition of 27 tcf of new field reserves discovered in Alaska's Prudhoe Bay area. These trends are shown in Fig. B.2.

Proved natural gas reserves have steadily increased from a 1918 value of 16 to 46 tcf in 1930 and 185 in 1950. These reserves continued to increase after 1950 at an average rate of 2.7% per year, reaching a peak of 293 tcf in 1968. Since 1968, proved reserves have shown a declining trend (except for 1970) with 1975 year-end reserves estimated at 228.2 tcf. The ratio of proved recoverable reserves to net production has steadily declined from a value of 31.9 in 1946 to 26.0 in 1950, 19.7 in 1960, 13.0 in 1970, and 11.3 in 1975. These trends since 1946 are also shown in Fig. B.2.

In comparison to domestic demonstrated reserves of 228.2 tcf at the end of 1975 and 237.1 tcf at the end of 1974, the U.S. Bureau of Mines estimated worldwide demonstrated reserves at 2253 tcf as of December 31, 1974. Although this value is, at least in part, a rough estimate since there is no international standard defining categories of natural gas reserves, it is nearly a factor of 10 greater than the United States' demonstrated reserves. Figure B.3 indicates the locations of these reserves. Approximately 31.1% are estimated

Table B.2. Domestic Demonstrated Reserves of Natural Gas
(Million cubic feet)

Region/State	Reserves as of 12/31/74	Reserves as of 12/31/75			
		Total	Non-Associated	Associated Dissolved	Under-Ground Storage
United States	237,132,497	228,200,176	156,785,551	67,173,979	4,240,646
New England[a]	0	0	0	0	0
Middle Atlantic	1,657,691	1,898,303	1,177,860	11,760	708,683
New Jersey	0	0	0	0	0
New York	165,546	215,843	103,446	38	112,359
Pennsylvania	1,492,145	1,682,460	1,074,414	11,722	596,324
East North Central	3,230,019	3,401,402	1,282,365	713,446	1,405,591
Illinois	399,414	380,804	1,100	3,626	376,078
Indiana	64,141	59,839	2,010	21	57,808
Michigan	1,458,254	1,606,749	483,268	536,766	586,715
Ohio	1,308,2]0	1,354,010	795,987	173,033	384,990
Wisconsin	0	0	0	0	0
West North Central	12,192,022	13,133,847	12,424,375	568,760	140,712
Iowa[b]	-	-	-	-	-
Kansas	11,704,731	12,661,181	12,405,912	150,413	104,856
Minnesota[b]	-	-	-	-	-
Missouri[b]	-	-	-	-	-
Nebraska	54,609	55,818	12,748	7,214	35,856
North Dakota	432,682	416,848	5,715	411,133	0
South Dakota[b]	-	-	-	-	-
South Atlantic	2,619,154	2,625,705	1,934,981	317,757	372,967
Delaware	0	0	0	0	0
Florida	308,866	266,904	0	266,904	0
Georgia	0	0	0	0	0
Maryland[b]	-	-	-	-	-
North Carolina	0	0	0	0	0
South Carolina	0	0	0	0	0
Virginia	44,707	47,465	47,465	0	0
West Virginia	2,265,581	2,311,336	1,887,516	50,853	372,967
East South Central	2,430,792	2,791,238	2,403,164	175,368	212,706
Alabama	507,370	770,981	732,799	38,182	0
Kentucky	844,002	812,630	638,055	42,985	131,590
Mississippi	1,079,420	1,207,627	1,032,310	94,201	81,116
Tennessee[b]	-	-	-	-	-
West South Central	158,096,878	147,422,578	114,197,242	32,613,955	611,381
Arkansas	2,113,404	1,993,273	1,836,725	132,373	24,175
Louisiana[c]	64,052,445	61,309,423	51,471,615	9,626,511	211,297
Oklahoma	13,390,312	13,083,028	10,250,503	2,612,725	219,800
Texas[c]	78,540,717	71,036,854	50,638,399	20,242,346	156,109

Table B.2. (Cont'd)

Region/State	Reserves as of 2/31/74	Reserves as of 12/31/75			
		Total	Non-Associated	Associated Dissolved	Under-Ground Storage
Mountain	19,676,653	19,202,889	15,374,597	3,541,840	611,381
Arizona[b]	-	-	-	-	-
Colorado	1,881,695	1,893,017	1,659,151	204,572	29,294
Idaho	0	0	0	0	0
Montana	901,260	929,986	686,350	73,912	169,724
Nevada	0	0	0	0	0
New Mexico	11,944,902	11,759,294	9,442,073	2,287,375	29,846
Utah	1,031,409	917,433	493,885	420,266	3,282
Wyoming	3,917,387	3,703,159	3,093,138	555,715	54,306
Pacific	37,061,204	37,534,776	7,976,959	29,229,547	328,270
Alaska	31,866,612	32,050,749	5,727,699	26,323,050	0
California[c]	5,194,592	5,484,027	2,249,260	2,906,497	328,270
Hawaii	0	0	0	0	0
Oregon	0	0	0	0	0
Washington[b]	-	-	-	-	-
Miscellaneous[d]	168,084	189,438	14,008	1,546	173,884
Gulf of Mexico[e]	35,347,841	37,332,642	32,879,111	4,453,531	0

a. Includes Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont.
b. Included in Miscellaneous.
c. Includes adjacent offshore regions.
d. Includes Arizona, Iowa, Maryland, Missouri, South Dakota, Tennessee and Washington.
e. Included in Texas and Louisiana.

Source: American Gas Association, *Gas Facts - 1975*, Table 2.

to be located in the U.S.S.R., 16.9 in Iran, 10.5 in the United States, and 5.2 in the African nation of Algeria.

B.1.2 Natural Gas Production

An analysis of natural gas production should be prefaced with a brief examination of the terminology and interrelationships most frequently used in describing the gas production industry. The approach taken here is to construct a diagram, synthesized from two of the more popular statistical references to provide a view of these interrelationships. This approach is intended to aid the reader in his understanding of the definitions given to gas production data both here and throughout the report.

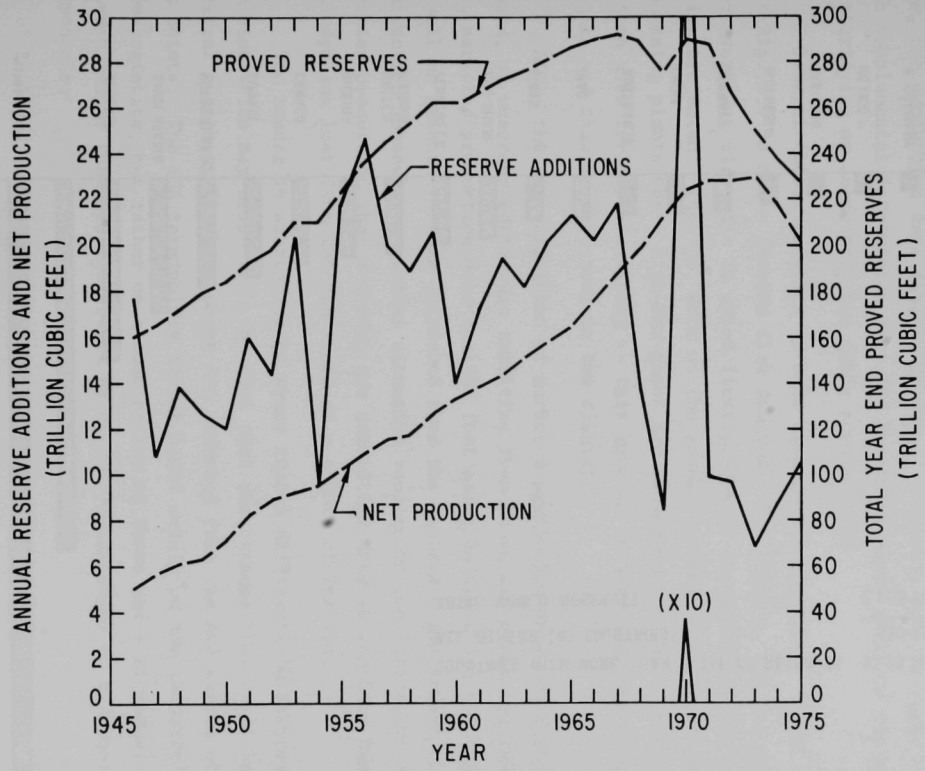


Fig. B.2. U.S. Natural Gas Reserve Additions, Net Production and Proved Reserves, 1945 - 1975

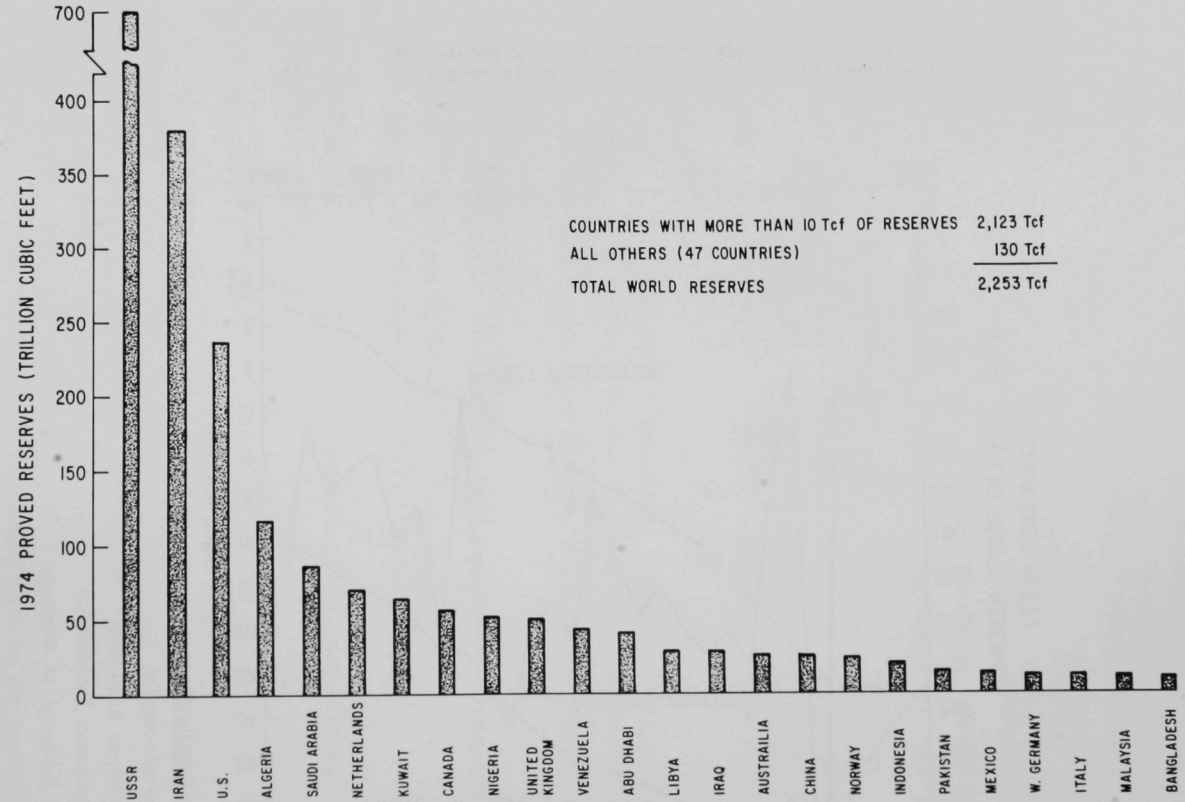


Fig. B.3. Worldwide Proved Reserves of Natural Gas, December 31, 1974

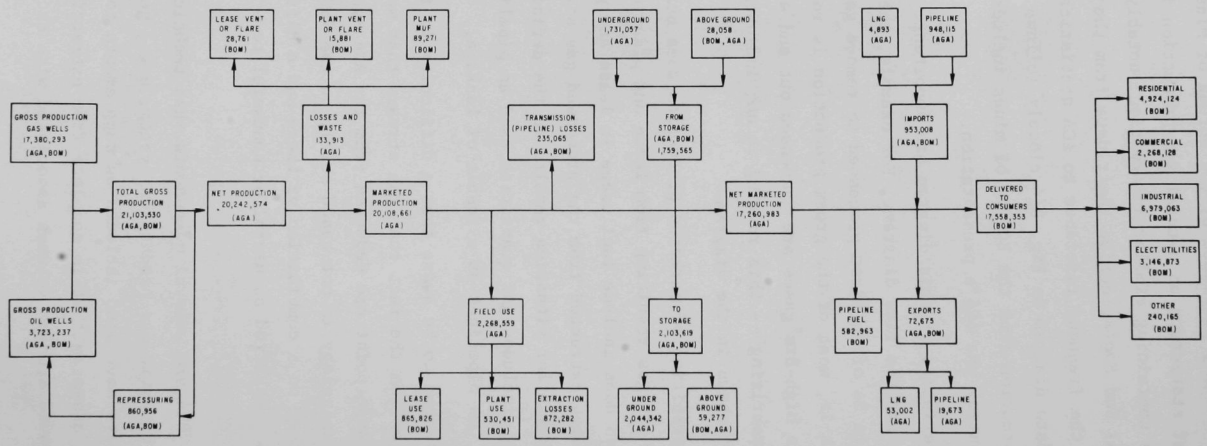
The *Natural Gas Annual*, published by the Bureau of Mines (BOM), is the principal source of statistics on natural gas production in the United States. Other sources containing similar information, notably the American Gas Association's (AGA) *Gas Facts*, derive their data from the Bureau's publication. Because of the frequent reference to AGA statistics in the literature, the production data diagram in Fig. B.4 closely follows their logic with supplemental information from the Bureau of Mines included for purposes of clarifying or augmenting the AGA's presentation.

Several characteristics of this diagram are important. First, note that Fig. B.4 is not a process flow diagram. For example, the gas used for repressurizing oil wells is often first processed to remove gas liquids before it is reinjected. That is, most of the gross production is routed through processing plants where high-Btu gases are condensed out and a return stream is then used for repressurizing -- this routing is not indicated by AGA statistics and thus is not shown in the diagram.

Also, the AGA definition of marketed production does not include vented, flared, or unaccounted-for gas resulting from lease and plant operations. But, marketed production does include fuel usage in lease and plant operations as well as gaseous volumes extracted from the processed gas stream as liquids (extraction losses). A similar situation results in the definition of net marketed production that includes gas quantities used as pipeline fuel but excludes gas lost from the pipelines as a result of leakage.

The reader is alerted to be aware that a difficulty in interpreting the AGA statistics may arise from the fact that gas streams that would leave a physical system at the same point are deducted from the AGA system at different points. The AGA terminology is not based solely on the industry's gas flow logistics, but rather on a combination of these and a differentiation between losses that are classified as useful or nonuseful to a downstream component.

Included in Fig. B.4 are several components that technically are not considered part of the domestic gas production system, e.g., gas imports and exports. These components have been included as supplements to the AGA presentation to provide a system that is complete from extraction to final consumption. Also included are gas volumes associated with each of the defined



Quantities are for 1975 and are in million cubic feet.

Fig. B.4. Domestic Natural Gas Production and Disposition, 1975

terms. Although these values are based on 1975 data, their relative proportions are typical of the production data of recent years.

Table B.3 summarizes the major production components on a national basis for each of the years 1950 through 1975. Further detail of the marketed production for 1975 is given by state and presented in Table B.4. These data indicate that the major producing region comprising Texas, Louisiana, Oklahoma, and Arkansas accounted for approximately 81% of all domestically produced natural gas during 1975. In 1955 this same region produced 75% of all domestic natural gas.

Included in the state totals for Alaska, California, Louisiana, and Texas are gas volumes produced from adjacent offshore areas. In 1975 slightly over 21% of all domestically produced natural gas was from offshore regions. This value compares to 14.7% in 1970, 5.8% in 1965, and 1.4% in 1955. Figure B.5 summarizes the history of marketed production from offshore areas and relates these data to the total U.S. marketed production. Offshore production from federal outer continental shelf (OCS) waters now accounts for over 80% of the total offshore production. This proportion has grown steadily (with some minor setbacks) from a low of 47% in 1957. Cumulative production from the OCS through 1975 accounted for 75% of the total offshore production of natural gas.

Annual natural gas production in the United States comprises approximately half of the total estimated world production. The proportion, however, has declined in recent years from 57.5% in 1970 to 45.7% in 1974. This trend is due primarily to a stabilization and slight decline in domestic production coupled with an increase in production in other parts of the world, notably Europe and Asia. Estimates of worldwide gross and marketed production for 1974 are given in Fig. B.6. The next largest producer to the United States is the U.S.S.R. with a 1974 marketed production of 9.2 tcf, followed by Canada with a 1974 marketed production of 3.0 tcf. (Production data presented in Fig. B.6 are given for the same 24 countries whose reserves are depicted in Fig. B.3).

B.1.3 Imports and Exports

Imported and exported natural gas is transported by two modes: by overland pipeline and by ocean-going tanker in liquefied form. A small amount

Table B.3. Production and Disposition of Natural Gas in the United States

	Production					Disposition					
	Gross[b]										
Year	Gas Wells	Oil Wells	Total	Repressuring	Net	Losses and Waste[b]	Marketed Production	Field Use	Net Change in Underground Storage	Lost in Transmission and Unaccounted for	Net Marketed Production
1950	5,603,200	2,876,450	8,479,650	1,396,546	7,083,104	801,044	6,282,060	1,187,473	54,492	175,437	4,864,658
1951	6,481,452	3,207,920	9,689,372	1,438,827	8,250,545	793,186	7,457,359	1,441,870	138,262	192,372	5,684,855
1952	6,839,177	3,433,389	10,272,566	1,410,501	8,862,065	848,608	8,013,457	1,483,754	176,684	203,646	6,149,373
1953	7,095,237	3,550,561	10,645,798	1,438,606	9,207,192	810,276	8,396,916	1,471,085	158,036	240,445	6,527,350
1954	7,466,007	3,518,843	10,984,850	1,518,737	9,466,113	723,567	8,742,546	1,456,883	102,106	215,709	6,967,848
1955	7,841,958	3,877,836	11,719,794	1,540,804	10,178,990	773,639	9,405,351	1,507,671	67,934	246,933	7,582,813
1956	8,306,550	4,066,355	12,372,905	1,426,648	10,946,257	864,334	10,081,923	1,420,550	136,470	212,992	8,311,911
1957	8,716,835	4,189,834	12,906,669	1,417,263	11,489,406	809,148	10,680,258	1,479,720	191,396	205,373	8,803,769
1958	9,154,051	3,992,584	13,146,635	1,482,975	11,663,660	633,412	11,030,248	1,604,104	83,081	283,597	9,059,466
1959	10,101,754	4,127,518	14,229,272	1,612,109	12,617,163	571,048	12,046,115	1,737,402	118,742	223,312	9,966,659
1960	10,853,426	4,234,485	15,087,911	1,753,996	13,333,915	562,877	12,771,038	1,779,671	131,694	274,231	10,585,442
1961	11,195,087	4,265,225	15,460,312	1,682,754	13,777,558	523,533	13,254,025	1,881,208	145,616	234,808	10,992,393
1962	11,702,382	4,336,591	16,038,973	1,736,722	14,302,251	425,629	13,876,622	1,993,128	86,487	285,726	11,511,281
1963	12,606,022	4,367,346	16,973,368	1,843,297	15,130,071	383,408	14,746,663	2,081,339	130,772	364,658	12,169,894
1964	13,035,200	4,405,100	17,440,300	1,638,161	15,802,139	339,996	15,462,143	2,082,029	128,804	302,781	12,948,529
1965	13,523,600	4,439,500	17,963,100	1,604,204	16,358,896	319,143	16,039,753	1,909,697	118,115	318,711	13,693,230
1966	13,893,921	5,139,918	19,033,839	1,451,516	17,582,323	375,695	17,206,628	1,772,708	68,855	401,203	14,693,862
1967	15,346,853	4,904,923	20,251,776	1,590,574	18,661,202	489,877	18,171,325	1,925,500[c]	184,829	296,214	15,764,782
1968	16,539,925	4,785,075	21,325,000	1,486,092	19,838,908	516,508	19,322,400	2,065,008[c]	95,539	325,062	16,836,791
1969	17,489,415	5,189,780	22,679,195	1,455,205	21,223,990	525,750	20,698,240	2,212,208[c]	119,500	331,587	18,034,945
1970	18,594,658	5,191,795	23,786,453	1,376,351	22,410,102	489,460	21,920,642	2,305,171[c]	398,160	227,650	18,989,661
1971	18,925,136	5,162,895	24,088,031	1,310,458	22,777,573	284,561	22,493,012	2,296,777[c]	331,768	338,999	19,525,468
1972	19,042,592	4,973,517	24,016,109	1,236,292	22,779,817	248,119	22,531,698	2,363,556[c]	135,734	328,002	19,704,406
1973	19,371,600	4,695,602	24,067,202	1,171,361	22,895,841	248,292	22,647,549	2,412,466[c]	441,504	195,863	19,597,716
1974	18,669,212	4,180,581	22,849,793	1,079,890	21,769,903	169,381	21,600,522	2,364,876[c]	83,663	288,731	18,863,252
1975	17,380,293	3,723,237	21,103,530	860,956	20,242,574	133,913	20,108,661	2,268,559	344,054	235,065	17,260,983

a. Production data include allowance for natural gas liquids content in the natural gas, and therefore differ from totals developed by AGA and included in Section II.
b. Includes gas (mostly residue gas) blown to the air but does not include direct waste on producing properties, except where data are available.
c. Beginning in 1967, computed by AGA from "Extraction loss" and "Lease and plant fuel."
d. Not available.

Sources: U.S. Bureau of Mines, *Natural Gas Annual*.
AGA, *Gas Facts - 1975*, Table 15.

Table B.4. Marketed Production of Natural Gas - 1975
(millions of cubic feet)

Region/State	Marketed Production	Region/State	Marketed Production
United States	20,108,661	East South Central	172,697
		Alabama	37,814
New England	0	Kentucky	60,511
		Mississippi	74,345
Middle Atlantic	92,304	Tennessee	27
New Jersey	0		
New York	7,628	West South Central	16,298,056
Pennsylvania	84,676	Arkansas	116,237
		Louisiana	7,090,645
East North Central	188,859	Oklahoma	1,605,410
Illinois	1,440	Texas	7,485,764
Indiana	346		
Michigan	102,113	Mountain	1,801,478
Ohio	84,960	Arizona	208
Wisconsin	0	Colorado	171,629
		Idaho	0
West North Central	871,006	Montana	40,734
Iowa	0	Nevada	0
Kansas	843,625	New Mexico	1,217,430
Minnesota	0	Utah	55,354
Missouri	30	Wyoming	316,123
Nebraska	2,565		
North Dakota	24,786	Pacific	478,578
South Dakota	0	Alaska	160,270
		California	318,308
South Atlantic	205,683	Hawaii	0
Delaware	0	Oregon	0
Florida	44,383	Washington	0
Georgia	0		
Maryland	93		
North Carolina	0		
South Carolina	0		
Virginia	6,723		
West Virginia	154,484		

Source: AGA, *Gas Facts - 1975*, Table 18.

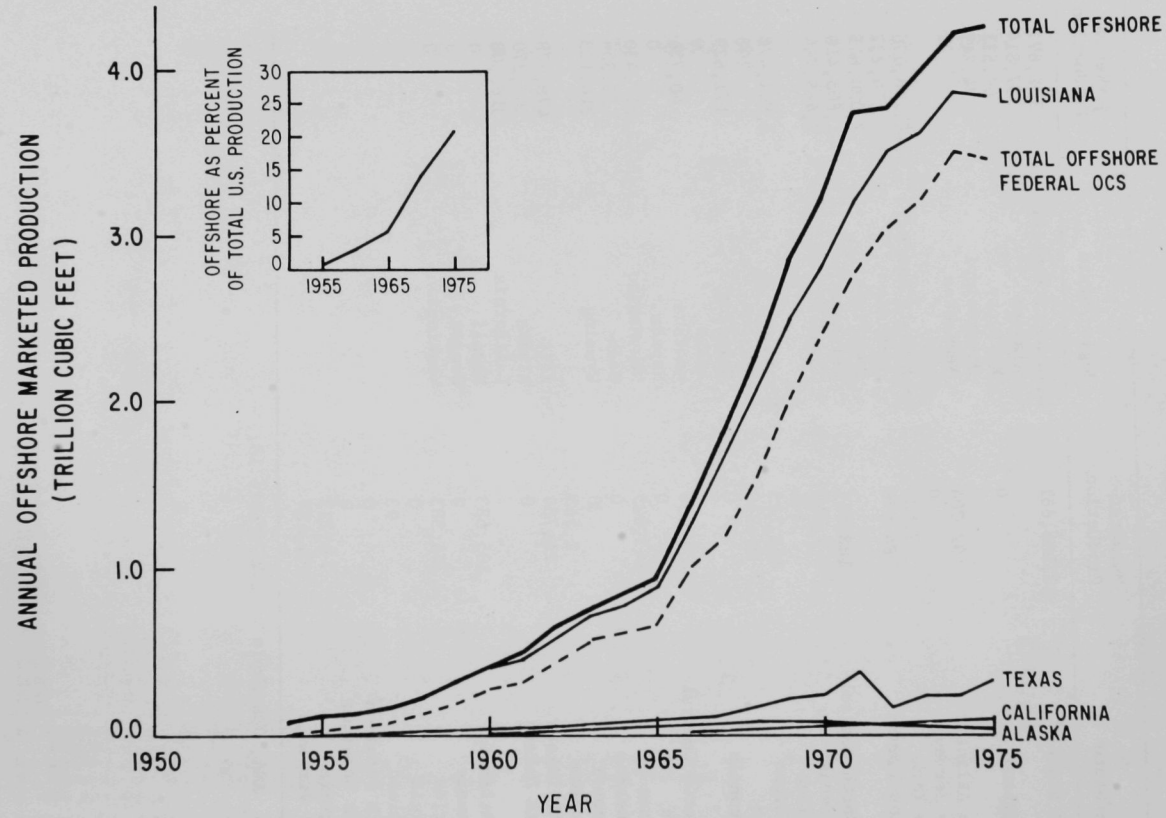


Fig. B.5. Marketed Production from Domestic Offshore Areas, 1954-1975

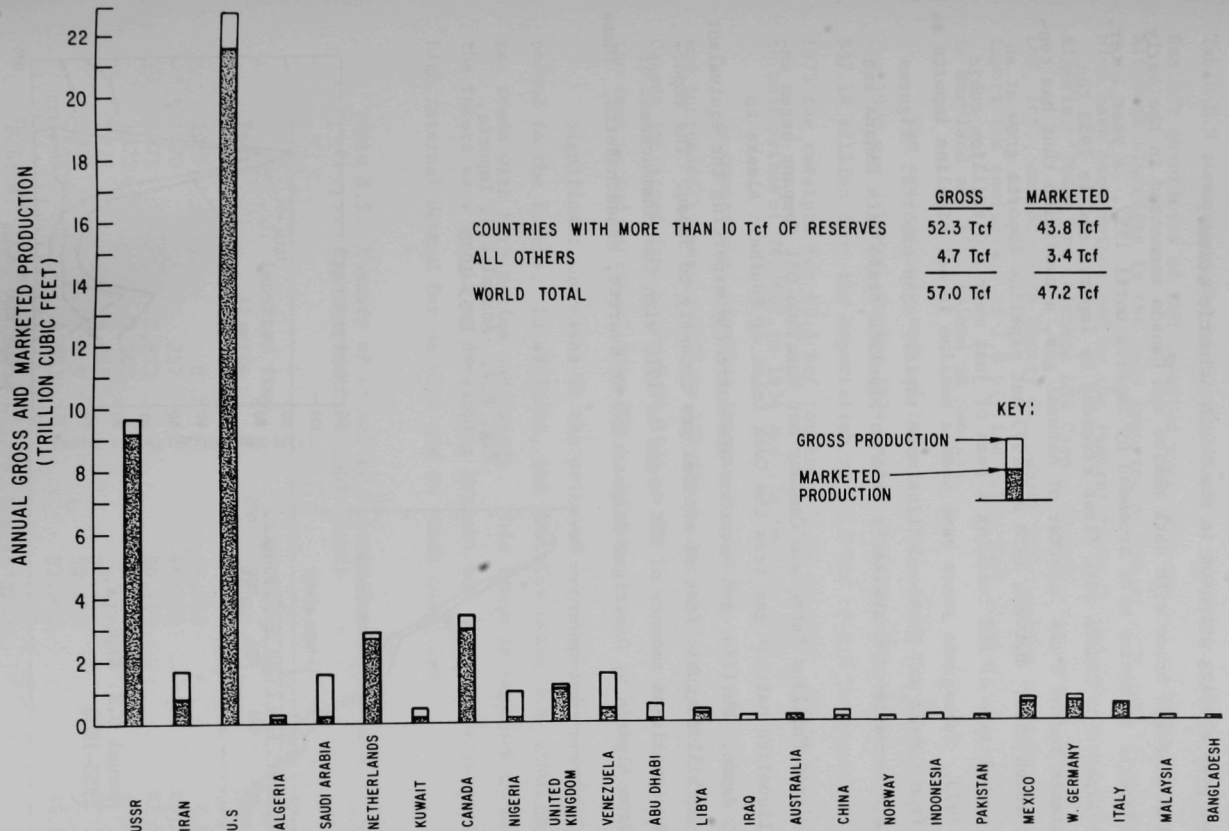


Fig. B.6. Worldwide Gross and Marketed Production of Natural Gas, 1974

of liquefied natural gas (LNG) has also been imported from Canada by tanker truck for peak shaving purposes in the North Atlantic states.

Pipeline gas trade with both Mexico and Canada commenced in the early 1950s. Exports to Mexico were exceeded by imports until 1957. A year later, pipeline exports to Canada were first exceeded by imports and in 1958 the United States became a net importer of natural gas, a condition that has continued through 1975. Between 1958 and 1973 net pipeline imports grew at an average annual rate of 16% reaching a peak of just over 1.0 trillion cubic feet in 1973. Subsequent years have seen a decline in net pipeline imports as imports from Canada and Mexico decline more rapidly than exports. Figures B.7 and B.8 summarize the available data on pipeline trade with Canada and Mexico.

In 1969 Phillips Petroleum Company and Marathon Oil Company began exporting liquefied natural gas from the Cook Inlet of Southern Alaska to Yokohama, Japan. Phillips and Marathon are currently exporting the equivalent of about 50 billion cubic feet of natural gas annually to Japan. The importation of significant amounts of LNG began in 1970 with the commencement of imports from Algeria by Distrigas Corporation at Everett, Massachusetts. These

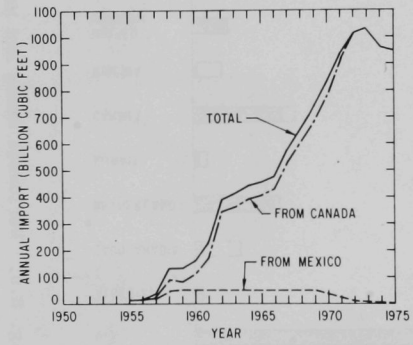


Fig. B.7. Annual U.S. Imports, 1955-1975

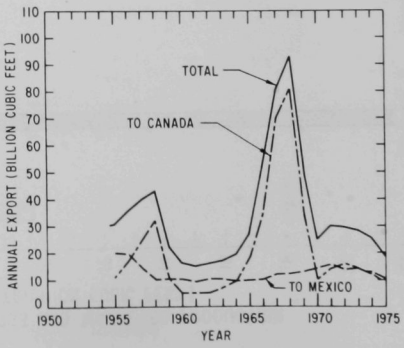


Fig. B.8. Annual U.S. Exports, 1955-1975

imports have increased from 757 MMcf in 1970 to nearly 5000 MMcf in 1975. Table B.5 summarizes the historical data on major LNG imports and exports. Smaller quantities of LNG imported over land are not included in these totals. Although Distrigas is the only importer of LNG at this time, four other companies have been authorized by the Federal Power Commission to begin imports from Algeria. These are Columbia LNG Corp., Consolidated System LNG Co., Eascogas LNG, Inc., and Southern Energy Co., which are involved in a joint proposal to import the equivalent of 1.0 billion cubic feet of Algerian gas at Cove Point in Maryland and Elba Island in Georgia.

The average unit cost of imported LNG at Everett, Massachusetts, during 1975 was 74¢/Mcf. During 1974 Phillips and Marathon had total receipts of $37.14 million from the exportation of 50.2 bcf of gas in liquefied form. In 1975 the receipts for 53.0 bcf totaled $73.11 million. These values correspond to unit prices of 74¢/Mcf in 1974 and 138¢/Mcf in 1975.[2]

By comparison, pipeline imports from Canada cost 55.34¢/Mcf during 1974 and increased by nearly 120% to 121.03¢ during 1975. Pipeline exports to Canada increased from 64¢/Mcf in 1974 to 78¢ in 1975. Exports to Mexico over the same period increased from 70¢ to 103¢/Mcf.[3]

Significant increases in the price of imported and exported gas are expected in the future. In addition, the past few years have shown decreases in gas trade with both Mexico and Canada. This trend is expected to continue in the future as a result of developing Mexican and Canadian policies and projected high internal demand for natural gas in those countries.

Table B.5. Summary of Liquefied Natural Gas Imports and Exports (million cubic feet)

Year	Imported from Algeria	Exported to Japan	Net Exports
1969	0	2,982	2,982
1970	757	44,275	43,518
1971	2,933	50,231	47,298
1972	2,263	47,882	45,620
1973	4,055	48,346	44,291
1974	0	50,258	50,258
1975	4,893	53,002	48,109

Source: AGA, *Gas Facts - 1975*, Tables 21-22.

B.1.4 Curtailments

The reporting of curtailments by interstate pipelines was not required by the Federal Power Commission until August of 1973. Now, interstate pipeline companies are required to file such a report with the FPC twice annually. Curtailments are defined for two types of service contracts, firm and interruptible. By a firm delivery contract, a pipeline company promises to deliver a fixed amount of gas over a specified time interval. A curtailment of these deliveries is the difference between the contracted volume and the amount the pipeline company is capable of delivering. Curtailments to interruptible customers, on the other hand, are based on reductions in normal deliveries to such customers (i.e., curtailments over and above normal curtailments of interruptible load).[4]

Table B.6 summarizes the net firm curtailments since September 1972. These data are reported to the FPC for an annual period beginning September 1 of each year. From the 1972/1973 through the 1975/1976 reporting period, annual firm curtailments have increased at an average compound rate in excess of 42%. Projections for 1976/1977 reporting period are for a 26.75% increase over the previous period. Actual curtailments may prove to be much greater than those projected as a result of the extremely harsh 1976/1977 winter.

Curtailments in interruptible sales between September 1975 and August 1976 totaled 444,341 MMcf or 67.9% of the interruptible sales requirement. Projections for the 1976/1977 reporting period are for 454,812 MMcf, nearly 72% of requirements.

Note that the curtailments shown here represent curtailments by 52 interstate natural gas pipeline companies to their customers. Because 90% of the natural gas sold by interstate companies is delivered to distributors who in turn provide gas to ultimate consumers, these curtailments are largely at the wholesale level. Several factors serve to ameliorate the impact of pipeline curtailments upon ultimate consumers. These factors may include warmer than normal winter weather, continued conversion to alternative fuels, conservation by fuel consumers, reduced gas demands due to industrial activity impacted by economic recession, increase in privately owned natural and synthetic gas supplies by distribution companies, and expansion of underground storage capability by interstate pipelines and distribution companies.

Table B.6. Wholesale Natural Gas of Net Firm Curtailments[a]

Reporting Period	Curtailments (MMcf)	% Increase over Previous Period
Sept. 1972-Aug. 1973	1,031,254	-
Sept. 1973-Aug. 1974	1,361,891	32.06
Sept. 1974-Aug. 1975	2,418,175	77.56
Sept. 1975-Aug. 1976	2,975,695	23.05
Sept. 1976-Aug. 1977 (Projection)	3,770,538	26.71

[a]Does not include curtailments to other reporting pipelines.

Source: FPC News, 9(50A) Dec. 10, 1976.

B.1.5 *Natural Gas Consumption*

Domestic natural gas consumption rose at an average annual rate of 6.8% between 1950 and 1972. After a peak consumption of 19,879,700 MMcf in 1972, annual gas usage declined 11.7% to a 1975 value of 17,558,353 MMcf. The historical pattern of domestic natural gas consumption is presented in Table B.7. Here the definition of consumption is consistent with the Bureau of Mines's definition of gas *delivered to consumers* and is calculated by deducting pipeline fuel usage from net marketed production and then adding net imports. (See Fig. B.4).

The relative quantities of natural gas consumed annually by each of the various economic sectors has remained fairly stable since 1950. Industrial gas consumption (including electric utility use) has accounted for approximately 60% of the annual gas usage. The residential sector typically has accounted for about 30% of the domestic gas consumption with the commercial sector and other miscellaneous users accounting for the remaining 10%.[5]

Table B.8 shows the relative distribution of domestic natural gas consumption for the year 1975. It is interesting to note that during 1975, electrical generation consumed 17.9% of all gas used during that year. Five years earlier, in 1970, gas consumed for electrical generation accounted for 20.7% of the total. This declining trend is expected to continue in the future as interstate natural gas is phased out as an allowable electric utility boiler fuel. In general, even in states such as Texas, which have large volumes of

Table B.7. Domestic Consumption of Natural Gas (million cubic feet)

Year	Net Marketed Production	Pipeline Fuel	Exports	Imports	Consumption
1950	4,864,658	125,546	25,727	0	4,713,385
1955	7,582,813	245,246	31,397	10,892	7,348,459
1960	10,585,442	347,075	16,100	156,843	10,379,110
1965	13,693,230	500,524	27,428	456,694	13,621,972
1970	18,989,661	722,166	69,813	820,781	19,018,463
1971	19,525,468	742,592	80,365	934,547	19,637,058
1972	19,704,406	766,156	78,014	1,019,464	19,879,700
1973	19,597,716	728,177	77,169	1,032,903	19,825,273
1974	18,863,252	668,834	76,789	959,285	19,076,914
1975	17,260,983	582,963	72,675	953,008	17,558,353

Source: American Gas Association, *Gas Facts - 1975*, Tables 15, 21, 22, & 53.

intrastate gas available for use, gas for electrical generation will decline as a result of state energy policies. Another factor that will contribute to a decline in the relative amount of gas consumed by electric utilities (and by the industrial sector in general) will be future curtailments of deliveries during high gas demand periods.

The geographical distribution of natural gas consumption during 1975 is also depicted in Table B.8. Texas is the largest consumer of natural gas, accounting for the consumption of 17.65% of the national total in 1975. Over 43% of the gas consumed in Texas was used for electrical generation and 45% was used for other industrial applications. Texas is followed by California, Louisiana, Illinois, and Ohio, which, respectively, consumed 9.84%, 8.12%, 6.16%, and 5.38% of the total gas used in 1975.

Gas utility customers have increased steadily since 1950 accumulating at an average of 2.5% per year between then and 1975. Consumption per customer has also increased steadily between 1950 and 1972, growing from an average of 175.4 in 1950 to 397.7 MMBtu/customer in 1972. Natural gas energy consumed per customer declined from 1973 through 1975 reaching 333.6 MMBtu/customer in 1975. Much of this decline is a result of decreases in industrial energy consumption, which has exhibited a general declining trend since 1971. The historical trends in number of gas utility customers and their average energy consumption are exhibited in Fig. B.9.

Table B.8. Natural Gas Delivered to Consumers, 1975

	Residential	Commercial	Industrial	Electric Utilities	Other	Total	%
New England:							
Connecticut	32,146	15,383	15,553	344	545	63,968	0.36
Maine, Vermont & New Hampshire	5,578	3,621	3,330	732	273	13,534	0.08
Massachusetts	90,226	33,819	23,986	1,437	3,993	153,461	0.88
Rhode Island	13,043	4,129	5,820	11	104	23,107	0.13
TOTAL	140,990	56,923	48,689	2,524	4,915	254,070	1.45
Middle Atlantic:							
New Jersey	129,406	52,147	52,361	8,601	1,199	243,714	1.39
New York	327,384	117,012	104,429	13,613	11,261	573,699	3.27
Pennsylvania	272,634	92,911	261,447	1,213	6,080	634,285	3.61
TOTAL	729,424	262,070	418,237	23,427	18,540	1,451,698	8.27
East North Central:							
Illinois	478,602	214,028	352,291	34,176	1,690	1,080,787	6.16
Indiana	162,858	68,545	223,383	10,994	1,956	467,736	2.66
Michigan	334,866	177,218	301,573	47,151	4,731	865,539	4.93
Ohio	427,817	163,976	341,612	6,139	5,381	944,925	5.38
Wisconsin	119,981	61,866	152,443	19,935	5,619	359,844	2.05
TOTAL	1,524,124	685,633	1,371,302	118,395	19,377	3,718,831	21.18
West North Central:							
Iowa	94,370	62,724	121,489	46,929	4,191	329,703	1.88
Kansas	98,372	48,714	124,378	127,818	2,991	402,273	2.29
Minnesota	14,416	62,412	100,539	22,709	27,239	327,315	1.86
Missouri	155,178	77,692	89,913	26,320	13,027	362,130	2.06
Nebraska	53,803	40,999	72,792	37,659	2,118	207,371	1.18
North Dakota	10,200	12,371	1,975	157	54	24,757	0.14
South Dakota	11,969	11,227	5,813	3,232	261	32,502	0.19
TOTAL	538,308	316,139	516,899	264,824	49,881	1,686,051	9.60
South Atlantic:							
Delaware	6,985	2,964	6,957	1,697	-	18,603	0.11
Florida	15,209	25,768	83,364	141,153	5,977	271,471	1.55
Georgia	87,184	45,152	145,479	40,282	4,286	322,383	1.84
Maryland & D.C.	82,380	32,836	43,165	451	4,630	163,462	0.93
North Carolina	27,466	18,144	62,094	101	3,471	111,276	0.63
South Carolina	18,211	15,115	70,329	14,566	2,087	120,308	0.68
Virginia	48,802	25,585	36,427	496	6,773	118,083	0.67
West Virginia	51,296	22,761	66,155	358	2,015	142,585	0.81
TOTAL	337,533	188,325	513,970	199,104	29,239	1,268,171	7.22
East South Central:							
Alabama	52,314	32,153	153,540	5,994	1,286	245,287	1.40
Kentucky	79,156	33,512	64,856	272	4,985	182,781	1.04
Mississippi	29,530	15,204	98,848	31,507	8,718	183,807	1.05
Tennessee	44,020	38,569	111,281	-	3,919	197,789	1.12
TOTAL	205,020	119,438	428,525	37,773	18,908	809,664	4.61
West South Central:							
Arkansas	48,543	32,676	128,151	31,818	615	241,803	1.38
Louisiana	96,221	27,427	922,673	356,130	23,235	1,425,686	8.12
Oklahoma	79,921	39,968	142,812	300,848	1,838	565,387	3.22
Texas	232,320	81,836	1,396,790	1,353,290	34,913	3,099,149	17.65
TOTAL	457,005	181,907	2,590,426	2,042,086	60,601	5,332,025	30.37
Mountain:							
Arizona	37,931	29,494	50,868	17,693	3,144	139,130	0.79
Colorado	99,933	72,843	65,609	52,930	3,445	294,760	1.68
Idaho	14,089	11,493	29,898	18	684	56,182	0.32
Montana	24,097	16,233	31,631	1,059	2,421	75,441	0.43
Nevada	11,091	9,989	10,043	24,152	4,976	61,251	0.35
New Mexico	27,826	12,491	57,773	64,239	10,309	172,638	0.98
Utah	59,736	6,018	48,104	2,725	37	116,620	0.67
Wyoming	12,128	10,159	43,618	819	94	66,818	0.38
TOTAL	286,381	168,720	337,544	164,635	25,110	982,840	5.60
Pacific:							
Alaska	10,393	8,475	22,388	19,619	5,940	66,815	0.38
California	631,398	232,911	581,609	274,483	7,328	1,727,729	9.84
Oregon	28,749	15,896	57,332	3	-	101,980	0.58
Washington	34,349	31,662	92,142	-	326	158,479	0.90
TOTAL	704,889	288,944	753,471	294,105	13,594	2,055,003	11.70
TOTAL UNITED STATES	4,924,124	2,268,128	6,979,063	3,146,873	240,165	17,558,353	
% of TOTAL Consumption	28.04	12.92	39.75	17.92	1.37	100.00	

Source: U.S. Bureau of Mines, *Natural Gas Annual - 1975.*

The average cost of gas has also increased steadily from its average 1950 customer value of 46¢/MMBtu. Between 1950 and 1970, the average annual price increase was approximately 1.66%. Between 1970 and 1975, customer gas prices have soared, increasing at about 15% per year. In 1975 the average price paid for gas was $1.29/MMBtu. Residential customers paid an average of $1.69; commercial, $1.38; and industrial consumers, $0.99/MMBtu. The historical trends in natural gas pricing are presented in Fig. B.10.

Note that the data presented in Figs. B.9 and B.10 are based on gas utility data that does not account for direct sales by producers to consumers. The data presented here accounts for approximately 87% of the total gas consumed in the United States. Most of the gas sales that are not included in the gas utility data are direct sales to industrial users. For the most part, the statistics presented on residential and commercial consumers in Figs. B.9 and B.10 may be regarded as essentially complete.

B.2 THE FUTURE

New large-scale technologies move very slowly from the research and development of conceptual plans to the successful operation of demonstration installations and ultimately to commercial deployment. The addition of a new increment of high-Btu gas supply requires many efforts ranging from the decision on which source to pursue to engineering design, obtaining necessary permits, making agreements with sellers, generating capital funds, construction of facilities, start-up testing, and finally commercial production. Given a typical lead time of five or more years for planning and implementation of a supply technology, few if any large projects applying substantive new technologies not already envisioned will be operable by 1985. Thus, projects capable of supplying high-Btu gas in 1985 will be initiated or otherwise decided upon within the next few years -- for the most part prior to 1980.

Decisions on future gas supplies will be made by corporations and individuals actively engaged in gas production or transmission at this time. These decisions are strongly influenced by historical and current trends as well as the decision maker's expectations of future conditions that potentially may affect the outcome of his decision. Four areas dominate the decision-making process: supply and demand, technology availability, economics, and regulation and policies.

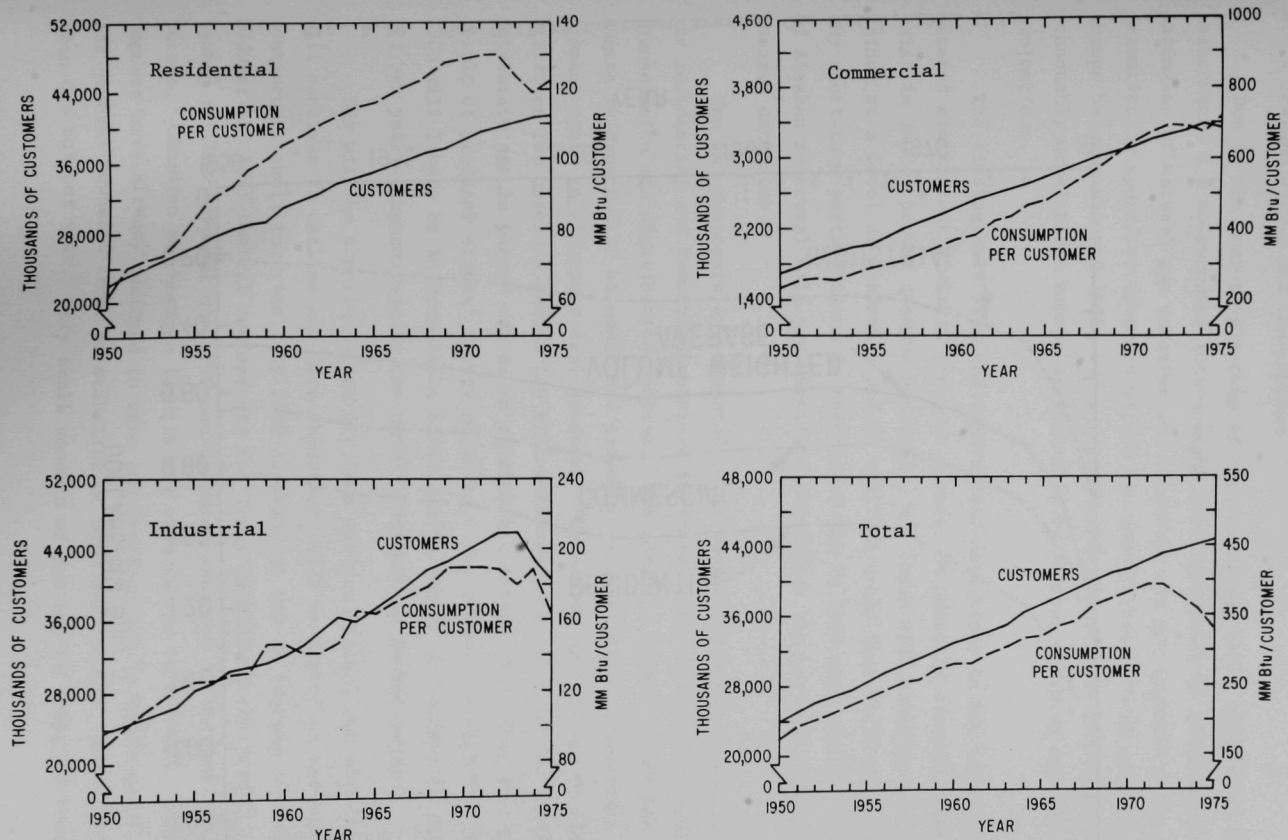


Fig. B.9. Domestic Gas Customers and Consumption per Customer, 1950-1975

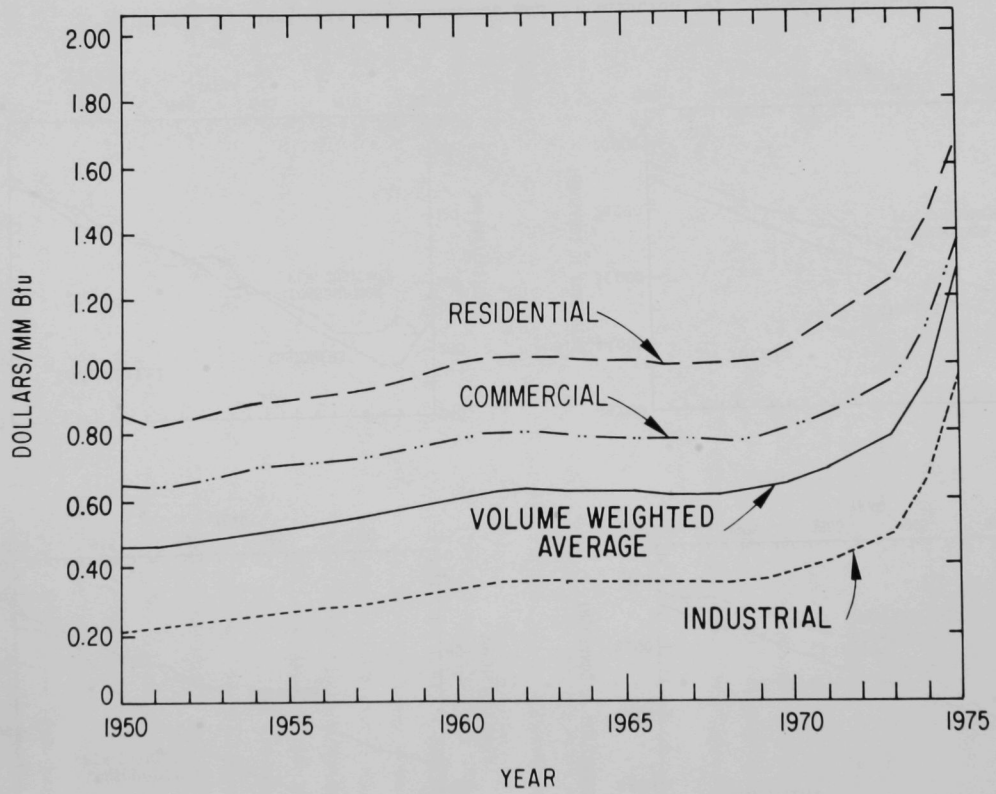


Fig. B.10. Gas Utility Customer Average Gas Price, 1950-1975

B.2.1 *Future Supply and Consumption*

Due to the near-term nature of the time frame being considered in this assessment, a a *no-surprise* future might most reasonably be considered. That is, estimates of natural gas reserves and resources are not expected to be revised dramatically upward or downward within the near future. These estimates will change between now and 1985, but this change is expected to evolve in a reasonably predictable manner approximated by current industry and government projections.

The finding rate from gas exploration activities is not expected to be altered significantly within the next decade. A possible downward trend may exist in annual proved reserve additions, but these will probably be maintained at a level of between 6 and 12 trillion cubic feet (tcf) per year. Any short-term perturbations in this trend (as in 1970 with the introduction of Alaskan reserves) will not significantly affect the overall resource and reserve estimates.

New gas customers are expected to be added without much restriction in the residential and commercial sectors in areas being serviced by major gas transmission and distribution systems. The addition of new industrial consumers is expected to be small and probably will not offset conversion by present users to alternate fuel sources. The use of natural gas by electric utilities for baseload generation will continue to decline in the future as interstate gas is phased out as an allowable utility boiler fuel and as a result of producer states' energy policies. The demand for high-Btu gas in 1985 will likely be in reasonable balance with supply at between 18 and 22 tcf per year -- approximately the amount consumed in recent years.

Gas will be supplied primarily from onshore fields, but this source will continue to decline and more dependence will be placed on the outer continental shelf reserves. By 1985 Alaskan gas may be flowing into the Midwest and East Central regions via the Trans Canadian-North Border pipeline system if that proposal wins FPC and Canadian approval in the very near future. Canadian and Mexican imports are expected to be nominal. Mexican imports have already declined to zero and Canadian gas is expected to continue its general downward trend or stabilize at some small value, probably less than 0.8 tcf per year. Very small amounts of gas may be supplied from the

gasification of liquid hydrocarbons and geopressured reservoirs, but these supplies will not be significant. Other developing technologies may be supplying significant quantities of high-Btu gas by 1985.

B.2.2 Technology Availability

Numerous systems are considered candidates for high-Btu gas supply in the future. These are:

1. Onshore reservoirs
2. Offshore reservoirs
3. Canadian and Mexican imports
4. Gasified liquid hydrocarbons
5. Alaskan reservoirs
6. Imported liquefied natural gas (LNG)
7. Gasified coal (both mined and in situ)
8. Oil shale gasification
9. Increased recovery in existing fields
10. Recovery from tight geological formations
11. Geopressured reservoirs
12. Gas occluded in coal

Several of these, including in situ coal gasification, oil shale gasification, recovery from tight geological formations, and the recovery of gas occluded in coal, are not considered viable options for high-Btu gas supply by 1985. Each of these technologies requires a significant amount of research and development before reaching the stage of commercial application. Several additional technologies are currently supplying very small amounts of high-Btu gas for domestic consumption, but, for various reasons, are not expected to supply significant quantities of gas by 1985. The further development of liquid hydrocarbon gasification will be limited for a lack of domestic feedstock and a high cost of imported feedstock. Increased recovery from existing fields probably will continue where economical situations exist, but quantities produced from these techniques are not expected to play a significant role in gas supply between now and 1985. Some gas is currently being produced from geopressured reservoirs in southern Texas. Although these reservoirs have a potential for supplying large quantities of natural gas in the future, the ratio of gas to water is so small that large scale extraction from this source will not be practical in the near future.

The remaining supply systems are considered viable for the 1985-1990 time frame being considered in this assessment. As mentioned previously, onshore production will continue to supply the majority of gas consumed in the United States, but production from this source will decline while offshore production and probably Alaskan reserves assume an increasing role in domestic gas supply. Only two supplemental gas supply technologies are considered potential candidates for the supply of significant quantities of high-Btu gas by 1985. These are the importation of liquefied natural gas and coal gasification. The technology for LNG has been developed and is being applied in the United States and in other parts of the world. Coal gasification is under active investigation in the United States and has been successfully demonstrated in Europe for the production of low-Btu gas. A final methanation process requires commercial proving prior to wide-scale application. Thus, the technology for coal gasification is nearly in hand and neither it nor the importation of LNG are thought to be constrained because of technological reasons.

B.2.3 Prices, Policy, and Regulation

Natural gas economics is not completely separable from many aspects of governmental regulation within the framework of the public utility character of gas transmission and distribution companies and federal controls over wellhead gas prices in the interstate market. In recent years, the maximum allowable wellhead price for new interstate gas has been revised upward from $.42 in 1974 to $.52/MMBtu in 1975, and most recently to $1.42/MMBtu. These prices are approaching a level where they may be competitive with unregulated intrastate gas and No. 2 fuel oil. For example, during the second quarter of 1976 new contracts for intrastate gas averaged $1.59 and dropped to $1.43/MMBtu during the third quarter.[6,7] During June 1976, imported oil prices averaged $13.47 bbl or $2.32/MMBtu while distillate or No. 2 fuel oil sold for an average of $2.81/MMBtu during 1975.[8]

Although the continued regulation of wellhead gas prices through the future is subject to some degree of uncertainty, new gas prices are expected to continue to approach a value competitive with intrastate gas and imported oil. Even if gas prices are deregulated, the legislation would also be expected to contain a predetermined escalation rate, thus in effect maintaining regulatory control over the transition period and prohibiting unusually large price increases over short time intervals.

Competitive bidding for federally controlled onshore and offshore lands is expected to continue under the current federal leasing program. Offshore lease sales are expected at a rate of 5 or 6 per year similar to the proposed leasing schedule issued by the Bureau of Land Management in November 1976.[9] Whether this schedule is realized will depend on the availability of sufficient manpower and equipment to explore potential lease areas. Lacking sufficient exploration capabilities, future leasing would progress at a slower rate. The leasing rate and the bonus paid per acre are important parameters in the economics of natural gas production. The leasing rate will have an effect on the amount of gas dedicated to the interstate market, whereas the bonus paid per quantity of gas discovered and produced determines a major percentage of the price required to pay back the producer on his investment.

Overall costs of gas production in 1985 by each of the technologies addressed in this assessment (and those expected to play an important role in gas production at that time) are all but impossible to estimate with any reasonable degree of certainty. Future costs associated with gas supplied by conventional technologies are highly dependent on finding rates and unknown future equipment and labor escalation rates. The cost of supplying gas from supplemental sources in 1985 are dependent primarily on future equipment and labor escalations and, in the case of imported LNG, its selling price at foreign ports. Due to these uncertainties, estimates of future gas prices, or price differentials between alternative supply options, are not made here. Rather, this assessment is based on estimates in constant 1975 dollars at present cost levels. Differentials in 1985 may, for any number of regulatory or other reasons, be substantially different than can be approximated by current cost estimates of future production and supply conditions.

Many other facets of governmental policy and regulation are capable of affecting the gas supply situation by 1985. For example, the development of the outer continental shelf, especially in undeveloped areas such as those off the Atlantic coast and in environmentally sensitive areas like Alaska, could be constrained as a result of tighter environmental regulations or an increase in the participation of adjacent states in the regulation of associated onshore land uses. Changes or developments in governmental policies related to increased reliance on foreign LNG or strip mining practices could potentially affect the relative availability and cost of technologically available supplemental supply options. Also, the Federal Power Commission's position on the

pricing of supplemental supplies could also have an impact on industry's willingness to invest in such projects. Rolled-in pricing of such supplies is much preferred by the gas industry, but the FPC has previously required incremental pricing of supplemental supplies that cost in excess of the maximum allowable wellhead gas price. Approval and construction of the North Border pipeline project would not only allow delivery of Alaskan gas to the lower 48 states, but its proposed location would permit advantageous use for the transportation of synthetic natural gas from coal gasification plants in Montana, North Dakota, and South Dakota. Indeed, its approval might even accelerate the development of current coal gasification plant proposals.[10]

There is a broad spectrum of possible developments related to the supply of natural gas in 1985, and it is not possible to predict the exact set of conditions that will exist at that time. Although one needs to be aware of these possible conditions, the assessment presented here is not sensitive to their outcome. Rather, this assessment should aid decision makers in formulating future policies and regulations. Possible future conditions have been presented to review a set of major options and circumstances that may exist by 1985. This information, like the historical data previously presented, is provided as a means of framing the social cost assessment within an overall view of the natural gas industry.

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APPENDIX C*

REFERENCE SYSTEM MASS AND ENERGY FLOW DIAGRAMS

*BBtu/d = Billion British thermal units per day
MMcfd = Million cubic feet per day

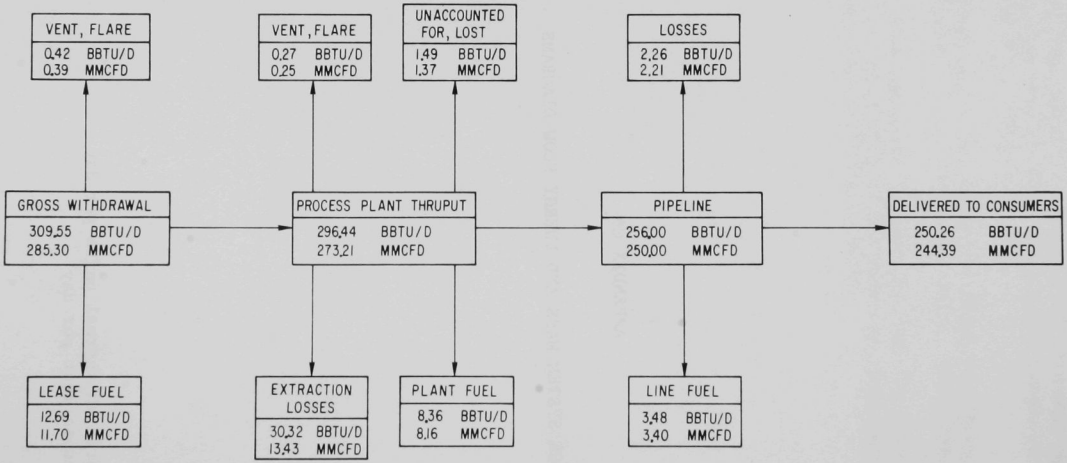

Fig. C.1. 250 MMcfd Offshore Reference System Energy and Materials Flow

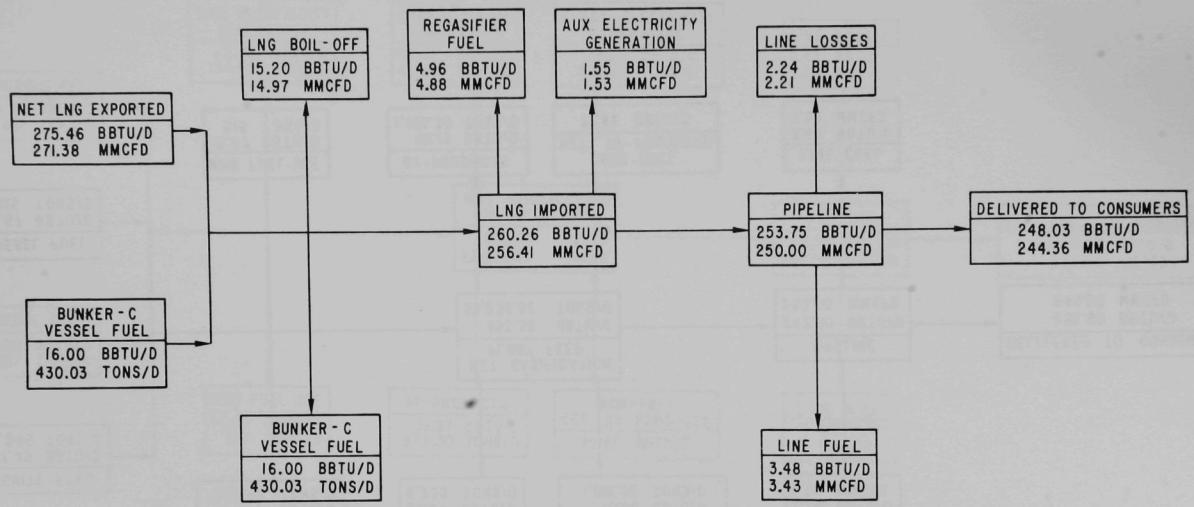

Fig. C.2. 250 MMcfd LNG Reference System Energy and Materials Flow

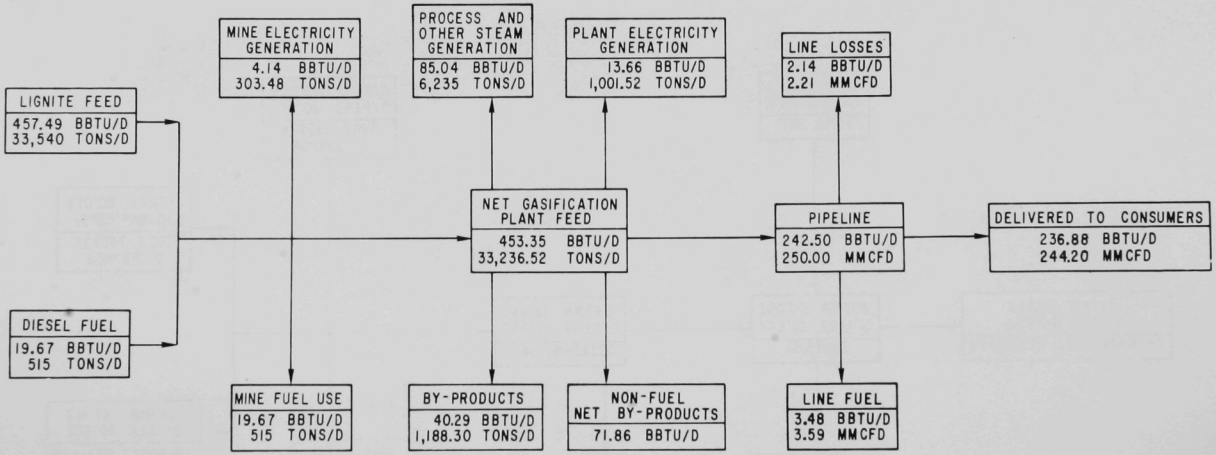

Fig. C.3. 250 MMcfd North Dakota Lignite Gasification Reference System Energy and Materials Flow

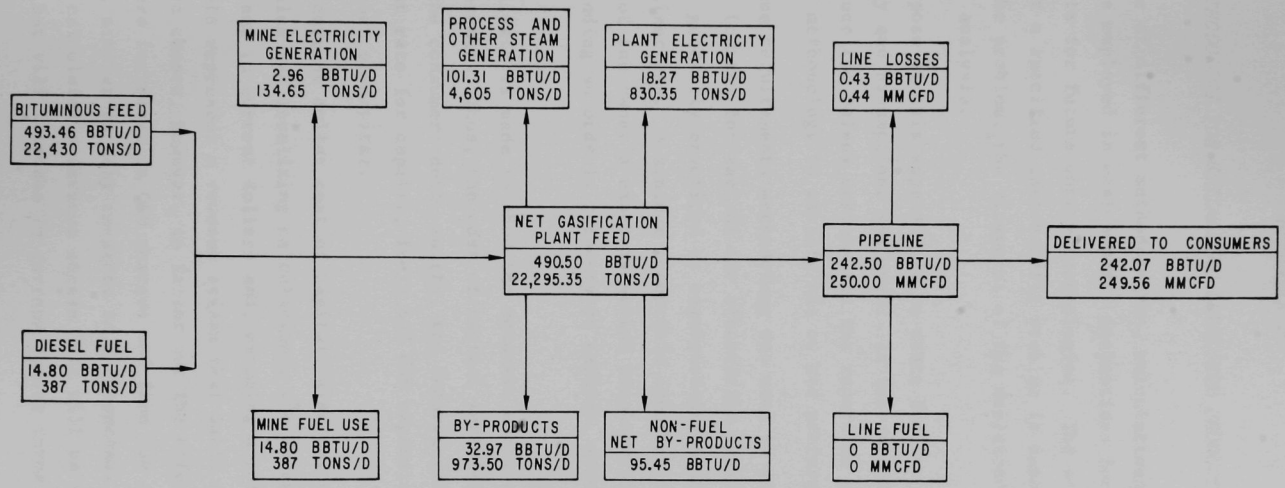

Fig. C.4. 250 MMcfd Southern Illinois Bituminous Coal Gasification Reference System Energy and Materials Flow

APPENDIX D

METHODOLOGY FOR ESTIMATING LEVELIZED PRODUCTION COSTS

A number of different methodologies, calculational procedures and assumptions are employed in cost-benefit evaluations for estimating levelized production costs for future energy technologies. The selection of a best methodology for a specified cost-benefit problem is dependent on the characteristics of the problem, the viewpoint of the decision-maker, and the intended purpose of the analysis.

The purpose of this appendix is to state for the interested reader the methodology and assumptions employed. In this manner, the reader will be able to reproduce the values derived for the report as well as alter the assumptions or methodology to satisfy his or her preferences.

A revenue requirements methodology was used to derive the levelized annual charges (costs) for each of the alternative systems. This type of methodology is generally practiced by regulated utilities and governmental planning organizations. A minimum acceptable annuity (as established by the specification of the owner's exact financial requirements) is used to recover all costs including an orderly recovery of capital, return to investors, and taxes.

The analysis is made to show the economic costs of alternatives on the the energy consumer. Thus, the cost of capital includes all components of cost seen by the consumer: debt, equity, and federal income taxes. The current dollar discount rate for capital, fuel, and O&M expenditures is assumed to be equal to the cost of capital.

If the current dollar cost of capital (discount rate) were used in the present value and levelizing calculations, the revenue requirement annuity would be constant in current dollars and, assuming a positive general inflation rate, would represent a revenue stream that would decline in real dollar terms. We have chosen, however, to factor out the effects of general inflation from future increases in O&M charges and from the owner's cost of capital. This approach, similar in many respects to the approach used by the MITRE Corporation,[1] calculates a revenue stream that will be uniform in real or constant dollars but will increase in current dollar terms at the general rate of

inflation. The net effect of this approach is the determination of a constant dollar annuity that is somewhat smaller than the current dollar annuity with which the reader may be more familiar. All costs are calculated on a constant 1975 dollar basis and the costs are discounted to 1985, the assumed date for commencement of high-Btu gas production.

Initially, the 1975 direct and indirect development and construction costs, excluding escalation and interest during construction, are determined from the literature. Suitable adjustments are made to the literature values, where necessary, to accurately reflect the assumptions regarding the reference system capacity, configuration, and future technological changes. For example, the number of offshore leases needed to find commercial quantities of natural gas in the future is expected to be somewhat greater than what has historically prevailed; these inccreases are recognized in the cost estimate.

The cash flow for direct and indirect construction costs is assumed to be as shown in Fig. D.1. All monies required during a given year are assumed to be committed at the beginning of that year. Interest charges accrue from the date of commitment until the end of the construction period. Figure D.1 also shows the monetary commitment function for a 5-year construction period.

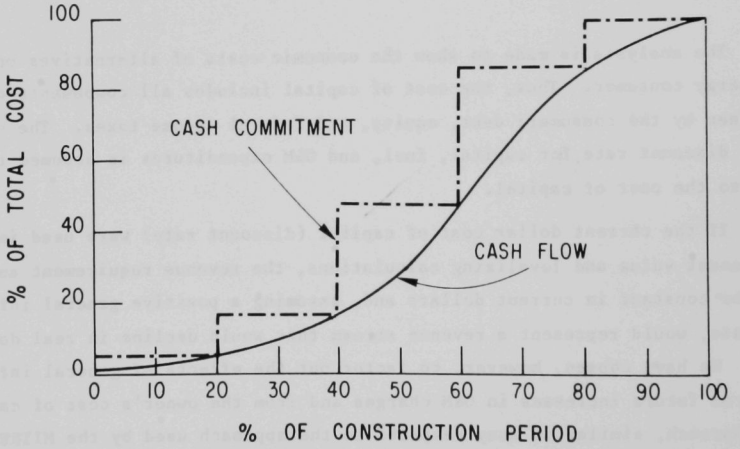

Fig. D.1. Construction Cash Flow and Cash Commitment Functions

Total capital investment, including escalation and interest during construction, in constant 1975 dollars, assuming 1985 start-up and a construction period of duration CP is given by:

$$CAP = C' \sum_{i=1}^{CP} (f_i - f_{i-1})\,(1 + e_r')^{i-1}\,(1 + i_r')^{(CP + 1 - i)} \qquad (1)$$

where:

CAP = total capital investment at start-up in 1975 dollars,

C' = direct and indirect construction costs at the beginning of the construction period in 1975 dollars,

CP = construction period in years,

f_i = fraction of C' committed at beginning of ith year, $f_0 = 0$,

e_r' = real escalation rate on capital equipment and construction, and

i_r' = constant dollar (real) interest rate during construction.

Real escalation and interest rates are determined respectively by the following equations:

$$1 + e_r' = \frac{1 + e_0'}{1 + inf} \qquad (2)$$

and

$$1 + i_r' = \frac{1 + i_0'}{1 + inf} \qquad (3)$$

where:

e_0' = observed (current dollar) long-term escalation rate on capital equipment and construction,

i_0' = observed (current dollar) long-term interest rate, and

inf = observed long-term general inflation rate.

Construction cost at the beginning of construction, C', is determined by:

$$C' = C \left\{\frac{1 + e_0'}{1 + inf}\right\}^{(1985-1975-CP)} \qquad (4)$$

where:

C = 1975 construction cost, excluding interest and escalation during construction in 1975 dollars.

Since the objective of this procedure is to compare the life cycle costs of dissimilar technologies, it is convenient to reduce future capital and operating expenses for each system to a single numeric value. It is even more convenient to have that value represent some average or *levilized* annual revenue requirement, necessary for continued ownership and operation of the system, that can be divided by the annual production capacity to give a representative levelized unit production cost.

Although a similar calculational methodology is applied to both capital and operating expenses, the discussion of the methodology is simplified if each of these components is treated separately. In the case of capital, the present value of future expenses is known (CAP), and an annuity necessary to recover this investment with its associated return on equity, interest, and taxes is sought. Typically in the case of annual operating expenses, only the first-year costs can be estimated with certainty. Unlike capital expenses, operating costs will normally increase from year to year as a result of inflationary and real economic forces. An annuity whose present value is equal to the present value of all future operating expenses is sought. Once determined, the capital and operating annuities can be summed to give a single levelized annual revenue requirement for each system. This value can be divided by the annual system capacity (assumed constant over time) to give a representative unit cost.

For the capital cost annuity calculation CAP is the 1985 present value of all capital-related expenses represented in 1975 dollars. Since a revenue requirement is sought, an after tax cost of capital is appropriate. In current dollar terms,

$$COC_o' = f_d\,(i_o) + f_e\,(r_o)\,(1 + \frac{TX}{1 - TX}) \qquad (5)$$

where:

COC_o' = observed (current dollar) after tax cost of capital,
F_d = fraction of debt financing,
f_e = fraction of equity financing,
i_o = observed (current dollar) bond interest rate,
r_o = observed (current dollar) return on equity, and
TX = incremental federal income tax rate.

Now, the sum of the present values of the annuity, a, necessary to recover capital costs is set equal to the present value of the capital investment, CAP,

$$CAP = \sum_{n=1}^{N} a \left\{ 1/(1 + COC_o') \right\}^N \tag{6}$$

where:

N = service life of system, and

a = required current dollar annuity in lieu of production royalties on revenue.

The summation reduces to

$$CAP = a \left\{ \frac{(1+COC_o')^N - 1}{COC_o' \ (1+COC_o')^N} \right\} \tag{7}$$

or

$$a = CAP \left\{ \frac{COC_o' \ (1+COC_o')^N}{(1+COC_o')^N - 1} \right\} . \tag{8}$$

Often, as is the case with the offshore production of natural gas, the federal government requires the producer to pay a specified fraction of his gross current dollar revenues in royalties. This payment increases the required annuity by the multiplicative factor R,

$$R = \frac{1}{1 - rr} \tag{9}$$

where:

rr = royalty rate on current dollar gross revenues.

Thus, the required current dollar annuity including royualties, A_o, is

$$A_o = (R) \times (a) = (R) \times \left(CAP \left\{ \frac{COC_o' \ (1+COC_o')^N}{(1+COC_o')^N - 1} \right\} \right) \tag{10}$$

If the current dollar annual charge rate (ACR_o) is defined as the fraction of original capital investment that needs to be recovered each year as annuity A_o, then

$$ACR_o = A_o/CAP = R \times \left\{ \frac{COC_o' (1+COC_o')^N}{(1+COC_o')^N - 1} \right\} \tag{11}$$

An equivalent current dollar cost of capital, COC_o, which includes the royalty factor, can be determined by:

$$\frac{COC_o (1+COC_o)^N}{(1+COC_o)^N - 1} = ACR_o \tag{12}$$

or

$$COC_o = ACR_o - \frac{ACR_o}{(1+COC_o)^N}, \tag{13}$$

which has a rapidly convergent iterative solution for COC_o.

The constant-dollar equivalent cost of capital, COC_r, can be found by:

$$1 + COC_r = \frac{1 + COC_o}{1 + inf}. \tag{14}$$

and a constant-dollar annual charge rate, ACR_r, can be found by:

$$ACR_r = \frac{COC_r (1+COC_r)^N}{(1+COC_r)^N - 1} \tag{15}$$

The purpose of Eq. 14 is to factor out the effect of general inflation from the current dollar cost of capital. Note that it was first necessary to calculate the current-dollar cost of capital, which includes federal taxes (Eq. 5), and the current-dollar annual charge rate, which includes the royalty factor (Eq. 11), since federal taxes and royalties are applied to the current-dollar earnings and annual revenues, respectively.

The annual 1975-constant-dollar *capital charge* for a given system assuming 1985 startup, ACC, is

$$ACC = ACR_r \times CAP. \tag{16}$$

Levelized annual operating and maintenance costs, LOM, are determined in a similar manner. The current-dollar cost of capital and general inflation factor cannot be as easily combined, however, to produce a constant-dollar cost of capital, since real escalation and inflation are not assumed to take place until the beginning of the second year of operation and all costs are discounted from the end of each year, including the first. Thus, because the exponents of these factors differ, they cannot be combined to substantially simplify the form of the equations.

Similar to Eq. 6, the sum of the present values of future O&M costs can be equated to the sum of the present values of an annuity or levelized cost. This statement takes the form of

$$OMC \sum_{n=1}^{N} \frac{(1+e_r)^{n-1}\,(1+inf)^{n-1}}{(1+COC_o')^n} = aa \sum_{n=1}^{N} \frac{(1+inf)^{n-1}}{(1+COC_o')^n} \tag{17}$$

where:

OMC	=	first year (1985) O&M cost in 1975 dollars,
N	=	service life of system,
e_r	=	annual real escalation of O&M cost (note that the O&M cost is assumed constant for first year and escalates at the beginning of each successive year)
inf	=	general inflation rate
COC_o'	=	observed (current dollar) after tax cost of capital (defined by Eq. 5)
aa	=	required annuity (levelized cost) without production royalties.

Given a 1975 annual O&M cost in 1975 dollars, OMC', the first year 1985 O&M cost is defined by

$$OMC = OMC' \times (1+e_r)^{1985-1975} \tag{18}$$

Solving Eq. 17 for aa,

$$aa = \frac{OMC \sum_{n=1}^{N} \frac{(1+e_r)^{n-1} (1+inf)^{n-1}}{(1+COC_o')^N}}{\sum_{n=1}^{N} \frac{(1+inf)^{n-1}}{(1+COC_o')^n}} . \tag{19}$$

Again, if production royalties are levied on gross revenues, the levelized O&M cost, including these royalty charges, LOM, is:

$$LOM = R \times aa = \frac{(R) \times (OMC) \sum_{n=1}^{N} \frac{(1+e_r)^{n-1} (1+inf)^{n-1}}{(1+COC_o')^n}}{\sum_{n=1}^{N} \frac{(1+inf)^{n-1}}{(1+COC_o')^n}} \tag{20}$$

where

LOM = levelized O&M costs including royalties on gross revenues, and

R = definition of Eq. 9.

It should be noted that the expression in Eq. 20 if written in current-dollar terms would be

$$LOM^* = \frac{(R) \times (OMC) \sum_{n=1}^{N} \frac{(1+e_r)^{n-1} (1+inf)^{n-1}}{(1+COC_o')^n}}{\sum_{n=1}^{N} \frac{1}{(1+COC_o')^n}} . \tag{21}$$

In this equation, the general inflation factor is not present in denominator summation, and the numerator is identical to that of Eq. 20. Since this equation neglects inflationary increases in the annuity while recognizing

inflationary increases in the annual cash flow, it is a current or nominal dollar levelizing technique rather than a constant dollar technique as is desired and given in Eq. 20.

Total levelized annual charges for a given system are the sum of annual capital charges (Eq. 16) and levelized operating and maintenance charges (Eq. 20). Thus

$$\text{Total Levelized Annual System Charges} = \text{ACC} + \text{LOM} \tag{22}$$

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