Synthetic Fuels Processing

COMPARATIVE ECONOMICS

edited by Arnold H. Pelofsky

Synthetic Fuels Processing

Comparative Economics

Edited by

Arnold H. Pelofsky

Manager, Energy Research Laboratory
Cities Service Research and Development Company
Cranbury, New Jersey

MARCEL DEKKER, INC. New York and Basel

Library of Congress Cataloging in Publication Data
Main entry under title:

Synthetic fuels processing.

Papers presented at a symposium sponsored by the Division of Industrial and Engineering Chemistry of the American Chemical Society held in New York, April 4-9, 1976.
Includes index.
1. Synthetic fuels--Congresses. I. Pelofsky, Arnold H. II. American Chemical Society. Division of Industrial Engineering Chemistry.
TP360.S95 662'.66 76-41472
ISBN 0-8247-6544-3

MARCEL DEKKER, INC.
270 Madison Avenue, New York, New York 10016

Current printing (last digit):
10 9 8 7 6 5 4 3 2 1

PRINTED IN THE UNITED STATES OF AMERICA

PREFACE

The papers that are included in this monograph were presented at a symposium sponsored by the Division of Industrial and Engineering Chemistry for the American Chemical Society at their Centennial meeting which was held in New York City, April 4-9, 1976. The symposium was entitled "Comparative Economics for Synfuels Processing."

Each author was asked to use a systems approach to present his economics, i.e., present economics on a module basis, because this approach would help the reader understand the assumptions that have been made to develop the economics of the process. They were asked to break out each stage and show the capital and operating costs for it. For example, for coal to gas and/or liquids processes, the modules might be:

Mining
Processing
Upgrading
Off-sites

The capital and operating costs for each module were to be listed. Also the unit operations for each module were to be included.

The off-site module, for example, could include the following:

Power system
Water treatment facilities
Oxygen production (if any)
Environmental control facilities
etc.

Furthermore, the authors were asked to calculate the profitability of their process by using the Discounted Cash Flow Rate of Return Method (DCF) and to show a sensitivity analysis of how the price of the product changes with the rate of return. If possible, energy and material balances were also to be included.

All of the authors were asked to calculate operating costs using the following economic basis:

	Basis
Use midyear 1975 $	
Project Life	20 years
Operating Factor	330 days/yr.
Capital Investment	
Cost of capital	10%
Working capital	60 day inventory 60 day cash supply
Land required	$5000/acre
Startup expense & organization	2% of capital investment
Annual Operating Cost (Next to the total dollars for each item list the unit cost in $/MMBTU of product.)	
Feedstock, $/ton or $/MMBTU	Do a sensitivity Analysis by varying cost of feedstock vs. profitability of venture.
Utilities	
Power ($/KWH)	0.015
Water ($/MGal)	0.05
Fuel ($/MMBTU)	1.50
Operating labor	$15000/man-year
Operating labor supervision	15% of operating labor
Maintenance	
Labor	2% of facilities investment
Supervision	15% of maintenance investment
Materials	2% of facilities investment
Administrative & support labor	20% of all other labor
Payroll extras-fringe benefits etc.	20% of all other labor
Insurance	2% of facilities investment
General administrative expenses	2% of facilities investment
Taxes (Local, State & Federal) (No investment tax credit)	50% of net profit
Depreciation	Straight line
Depletion allowance	Specify method used

By-Product credit

List quantity of each as $/ton or $/MMBTU

Most of the authors followed this proposal format except those whose presentation did not conform; these papers will be obvious to the reader. However, enough information is included to allow the reader to make the necessary calculations to put the papers on a common basis if he should so choose.

I wish to express appreciation to Marvin I. Greene who co-chaired this symposium with me. I also thank Cities Service R & D for the time to allow us to work on this symposium. Also, we thank Rosemary Szymanski and Marion Gattsek for their invaluable assistance in compiling this manuscript for publication and to the authors and and participants whose contributions and papers and ideas made this symposium a success.

Arnold H. Pelofsky

CONTRIBUTORS

Martin R. Adams, Office of Program Planning and Analysis, Fossil Energy, Energy Research and Development Administration, Washington, D.C.

I. N. Banchick, Davy Powergas, Inc., Lakeland, Florida

Roger E. Billings, Billings Energy Research Corporation, Provo, Utah

K. B. Burham, Institute of Gas Technology, Chicago, Illinois

Elsio Del Bel, Energy Research and Development Administration, Pittsburgh Energy Research Center, Pittsburgh, Pennsylvania

W. C. Dickinson, Lawrence Livermore Laboratory, Livermore, California

T. D. Donakowski, Institute of Gas Technology, Chicago, Illinois

Cyril W. Draffin, Office of Program Planning and Analysis, Fossil Energy, Energy Research and Development Administration, Washington, D.C.

Gerald M. Drissel, Air Products and Chemicals, Inc., Allentown, Pennsylvania

W. J. D. Escher, Institute of Gas Technology, Chicago, Illinois

Emmet J. Ferretti, Dravo Corporation, Pittsburgh, Pennsylvania

Sam Friedman, Energy Research and Development Administration, Pittsburgh Energy Research Center, Pittsburgh, Pennsylvania

C. S. Goddin, Amoco Production Company, Tulsa, Oklahoma

D. P. Gregory, Institute of Gas Technology, Chicago, Illinois

D. E. Hall, Pacific Gas and Electric Company, San Francisco, California

Richard W. Hyde, Arthur D. Little, Inc., Cambridge, Massachusetts

Edward Interess, Arthur D. Little, Inc., Cambridge, Massachusetts

John F. Kamody, Engineering and Construction Division, Koppers Company, Inc., Pittsburgh, Pennsylvania

Sidney Katell, Process Evaluation Group--MMRD, Bureau of Mines, U.S. Department of the Interior, Morgantown, West Virginia

Chris W. Knudsen, Office of Program Planning and Analysis, Fossil Energy, Energy Research and Development Administration, Washington, D.C.

Stephen M. Kohan, Stanford Research Institute, Menlo Park, California

Quinton Lee, Department of Applied Science, Brookhaven National Laboratory, Upton, New York

J. W. Loeding, Institute of Gas Technology, Chicago, Illinois

Paul Marnell, Oil Shale Technology, American Lurgi Corporation, Hasbrouk Heights, New Jersey

J. H. Marten, Davy Powergas, Inc., Lakeland, Florida

R. Z. Mason, Williams Brothers Process Services, Inc., Tulsa, Oklahoma

H. James Michaels, Engineering and Construction Division, Koppers Company, Inc., Pittsburgh, Pennsylvania

Ravindra M. Nadkarni, Arthur D. Little, Inc., Cambridge, Massachusetts

Marc S. Newkirk, International Materials Corporation, Burlington, Massachusetts

J. B. O'Hara, The Ralph M. Parsons Company, Pasadena, California

J. G. Patel, Institute of Gas Technology, Chicago, Illinois

Stephen A. Reber, Arthur D. Little, Inc., Cambridge, Massachusetts

August H. Schutte, Arthur D. Little, Inc., Cambridge, Massachusetts

T. V. Sheehan, Department of Applied Science, Brookhaven National Laboratory, Upton, New York

Richard C. Sparling, The Chase Manhattan Bank, North America, New York, New York

Meyer Steinberg, Department of Applied Science, Brookhaven National Laboratory, Upton, New York

R. Peter Stickles, Arthur D. Little, Inc., Cambridge, Massachusetts

T. K. Subramanian, Davy Powergas, Inc., Lakeland, Florida

R. V. Teeple, The Ralph M. Parsons Company, Pasadena, California

Luella G. White, Process Evaluation Group--MMRD, Bureau of Mines, U.S. Department of the Interior, Morgantown, West Virginia

Paul M. Yavorsky, Energy Research and Development Administration, Pittsburgh Energy Research Center, Pittsburgh, Pennsylvania

CONTENTS

CHAPTER I

ECONOMICS OF CRUDE OIL AND NATURAL GAS
COST OF ADDING PRODUCTION

Richard C. Sparling

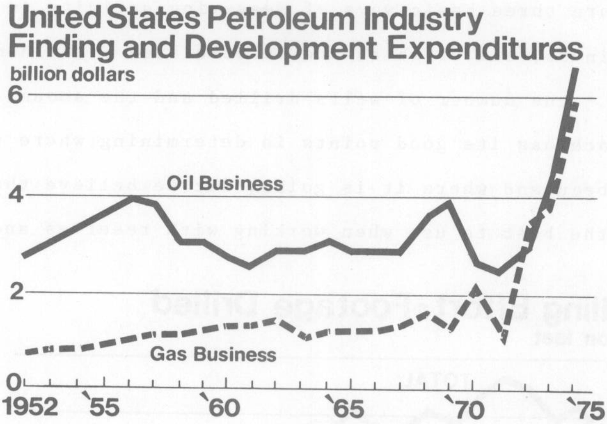
A few years ago we at Chase initiated a line of research revolving around the finding and development of petroleum in the United States. The basic premises were set down in a presentation entitled "Oil and Gas - Two Industries in One". This paper I am presenting today continues that line of research and will present some background for comparative use as other topics are presented throughout this meeting.

To get you acquainted with our approach, I will briefly run over the concept we use. The petroleum exploration and development industry is in the nature of two businesses carried on by the same company. The "oil business" is concerned with the discovery and production of crude oil as the main product and associated natural gas and gas liquids as the by-products. Conversely, non-associated natural gas is the primary product involved in the "gas business" with non-associated gas liquids and lease condensates as by-products. I should like to emphasize that we do not attempt to allocate between oil and natural gas, but between the "oil business" and the "gas business", which is not the same thing. In allocating between the "oil business" and the "gas business", we have made the basic assumption that operators are looking for what they find. If the expenditure of a sum of money results in what is classified by the industry as a successful oil well, then that expenditure is charged to the "oil business" regardless of the original intention of the operator. From an economic standpoint, it is what you find that matters, not what you are looking for. The payoff is on results, not intentions. Dry hole cost, both exploratory and developmental, are allocated in the same proportion as the cost of successful wells.

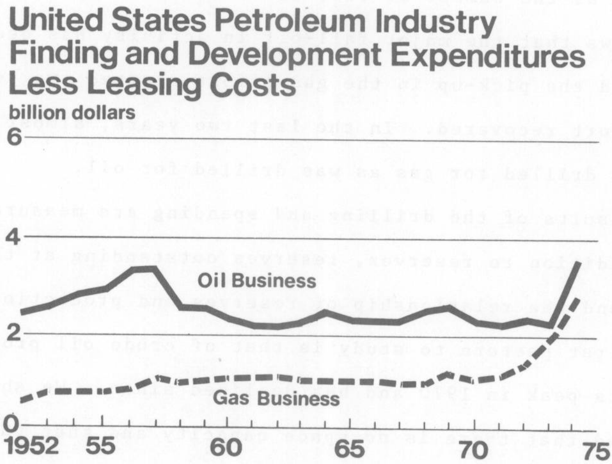
The other major expenditure that is allocated is that amount spent for lease acquisitions or bonus payments. To be consistent, we should wait until the leases are explored and developed and then allocate those expenditures in proportion to the successful oil and gas wells. However, as this process takes many years, we have allocated these costs instead on the basis of whether the areas involved are generally considered by the industry to be mainly oil bearing or gas bearing.

Exploratory costs - geological and geophysical expenses and lease rentals - complete the list. Although not strictly capital items, they play an integral part in the search for oil and gas. These are divided on the basis of the proportions of exploratory oil and gas wells drilled.

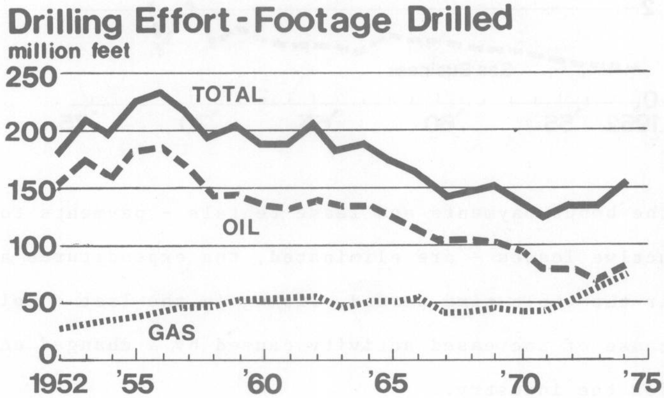
By using these basic assumptions, we have been able to generate the amount of money spent for the finding and development of oil and gas in the United States. As you see, there has been a considerable upturn in the last several years. Spending for the gas effort even moved ahead of the oil side in 1972. This was caused primarily by offshore bonus payments, a necessary but unproductive outlay.



If the bonus payments and lease rentals - payments to hold non-productive leases - are eliminated, the expenditures are almost level over the whole time period, rising in the last couple of years because of increased activity caused by a changed economic outlook for the industry.



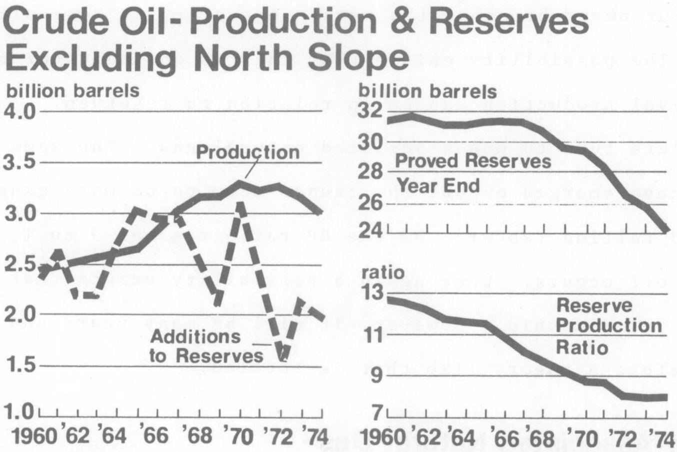
There are three basic ways of measuring activity in the oil and gas business, all of which are interrelated - the number of active rigs - the number of wells drilled and the amount of footage drilled. Each has its good points in determining where the industry has been and where it is going, but we believe that footage drilled is the best to use when working with reserves and costs.



A look at the number of feet drilled devoted to the oil and gas efforts shows that the major fall-off in activity has been in the oil side and the pick-up in the gas effort started two years before the oil effort recovered. In the last two years, almost as much footage was drilled for gas as was drilled for oil.

The results of the drilling and spending are measured by production, addition to reserves, reserves outstanding at the end of the year, and the relationship of reserves and production.

The first pattern to study is that of crude oil production. It readched its peak in 1970 and has declined since. We should keep in mind that there is no space capacity and that the industry has been producing all out since 1971. The second result of the drilling and spending effort is the gross addition to reserves and



reflects the downward trend in the effort. We do not have time to go into all the reasons for the downturn, suffice it to say they revolve around economic incentives. You can also see that additions fall below production in all but three years since 1962. This leads to proved reserves estimated to be in the United States, excluding the North Slope at each year end. The differences between production and reserve additions have caused the year-end reserves to fall from a peak of 31.8 billion barrels in 1961 to its present level of 24.7 billion barrels.

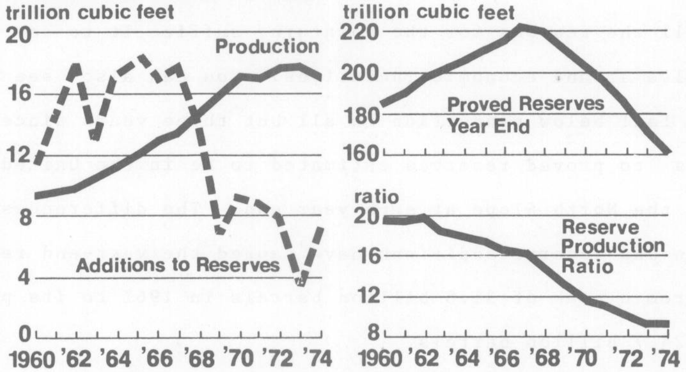
You might wonder why the North Slope is excluded from our calculations even though it is part of the United States. The answer is quite simple - size. The magnitude of the reserve and the smallness of the cost (not including the pipeline) distorts all of the relationships that exist for the area below the Brooks Range in Alaska.

As production rose and the reserve fell, the relationship between them changed. The ratio falls continually. As production dropped in the last couple of years, the ratio approached an 8 to

1 level, but never broached the mark. Actually, it rose slightly in 1974. The possibility exists that this is an indicator of the minimum level production can be in relation to reserves.

Now lets turn to non-associated natural gas. The same basic patterns have emerged except the trends seem to be more exaggerated - rising and falling faster. As the RP ratio reaches 9 to 1, a levelling off occurs. Once again a possibility exists that this is a minimum relationship. However, it will be many years and many debates before a theory like that is settled.

Non-Associated Natural Gas - Production & Reserves Excluding North Slope



The combination of drilling and spending over a period of time has added to the ability of the industry to produce oil and gas. However, the capital outlays in any one year cannot be tied to any increase in production for that year. It can take up to three or four years to bring new oil discoveries to market and five to six years for certain offshore gas finds. The extreme example will be close to ten years from the time of the Prudoe Bay discovery until the time it reaches the market place. An additional three years can be added if the timing is taken back to the year the lease was acquired. This time lag must be taken into account.