

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672

1062 SCOMM 28: JOINT GAS PIPELINE COMMITTEE. 1981-82

1062

are unwilling to make a considerable financial commitment to the project without participation in decisions relating to expenditure of funds. Without equity participation and its resulting voice in project management, the producers will not support the project with producer company funds. Without producer support private financing will be impossible.

Since the execution of the Cooperative Agreement and the formation of the Design and Engineering Board, the North Slope producers have been working with the Alaskan Northeast partnership in reviewing the pipeline and plant design, the cost estimates, and financing parameters. Their contribution has been valuable given their experience with the North Slope production facilities and the Alyeska oil line. Their continued participation, beyond that required for financing, is needed to help ensure a timely, cost effective completion of the ANGTS.

Concern has been expressed that producer participation in the ownership of the pipeline could lead to restrictions on pipeline capacity expansion or on access to the pipeline by non-owner shippers. Alaskan Northwest is confident that these problems will not develop. First, the producers' equity position will be limited to a minority interest. Second, Section 13 of the ANGTA requires that the FERC include a condition in Alaskan Northwest's certificate which provides that any one who wants to transport gas in the ANGTS must not be discriminated against in the terms and conditions of service on the basis of degree of ownership, or lack thereof. Third, the FERC has jurisdiction

under the Natural Gas Act to review any expansion of the capacity of the Alaska segment. Finally, the proposed waiver provides that the FERC, after consultation with the Attorney General, must find that producer participation will not create or maintain a situation inconsistent with the anti-trust laws or create restrictions on access to the ANGTS for non-owner shippers or restrictions on capacity expansions. Thus, the FERC will assure that the producers' involvement and participation is not inconsistent with the anti-trust laws.

2. Prudhoe Bay Gas Conditioning Plant

The President proposes waiver of Section 2, Paragraph 3 (the first sentence) of the President's Decision, Pub. L. No. 95-158, to include the gas conditioning plant in the approved transportation system and in the final FERC certificate to be issued under the Natural Gas Act, and the application of Section 5, Condition IV-2 of the Decision to such plant.

A Prudhoe Bay conditioning plant has been recognized as essential to permit the delivery of North Slope gas to markets in the lower 48 states. The ANGTS has special conditioning requirements for the gas to be transported through the system. Unlike existing gas pipelines, the Alaskan gas pipeline segment will be a high pressure pipeline transporting chilled gas. This requires extraordinary inlet compression and cooling and the removal of a greater than normal percentage of carbon dioxide, water and liquefiable hydrocarbons. Accordingly, gas processing costs for Alaskan gas are much greater than the processing costs that normally occur in the lower 48 states.

The producers' willingness to make a substantial financial commitment to the project also is predicated on the inclusion of the conditioning plant as a part of the ANGTS to permit a recovery of costs associated with constructing and operating the plant, plus a reasonable return on invested capital, pursuant to a FERC-approved tariff.

Inclusion of the conditioning plant within the ANGTS and the Alaskan certificate will require amendments to the pending Alaskan Northwest certificate application at the FERC and Commission review and approval of such application and the plant tariff. Inclusion of the plant in the system will give the FERC the opportunity and the authority to review the plant design and its estimated cost of construction and authority to review and approve the tariff provisions applicable to the plant governing recovery of the plant costs. Nothing in the proposed waiver restricts or modifies the Commission's responsibilities to review the application and tariff and to find that such tariff is "just and reasonable" and in the public interest prior to issuance of a final certificate.

Application of the incentive rate of return mechanism to the conditioning plant would substantially delay issuance of a final certificate. However, the actual construction costs will be reviewed by the Federal Inspector, and only prudently incurred plant costs will be recovered in rates.

3. Billing Commencement

The President proposes to waive Section 5, Condition IV-3 of the Decision, Pub. L. No. 95-158, to authorize the FERC to

approve tariffs that permit: (a) recovery of the full cost of service of the Canadian pipeline segment (i) upon completion and testing of the Canadian segment but (ii) not before a date certain, as established by the FERC, to be the most likely date for the entire approved transportation system to commence operation; and, (b) recovery of actual operation and maintenance expenses, current taxes, and amounts necessary to service debt, including interest and scheduled retirement of debt for both the Alaska pipeline segment and the gas conditioning plant (i) upon their individual completion and commissioning but (ii) not before a date certain, as established by the FERC, to be the most likely date for the entire approved transportation system to commence operation.

Condition IV-3 of the President's 1977 Decision prohibits any tariff which would require the purchaser or ultimate consumer to pay any charge with respect to the pipeline at any time prior to completion and commissioning of the entire pipeline system. In Orders 31 and 31-B the FERC approved a tariff for Alaskan Northwest which provides that upon completion and commissioning (a government agency declaration that the system is ready to operate) of the ANGTS, the risk of service interruption or project failure is assumed by consumers. Specifically, under Commission Orders 31 and 31-B the FERC approved tariff permits Alaskan Northwest to charge a rate which will recover actual operating and maintenance expenses, current taxes, and debt service, including interest and scheduled debt retirement (but not return of, or on, equity investment), upon completion and commissioning of the pipeline segments

of the ANGTS, before gas is actually transported or before completion of the gas conditioning plant.

The proposed waiver would permit the FERC to approve, at its discretion and only after a finding that the public convenience and necessity is served, a tariff permitting billing to commence for each individual segment of the ANGTS -- the gas conditioning plant, the Alaskan pipeline segment, and the Canadian segment of the ANGTS -- upon their separate completion and commissioning, but not before a target operation date established by the FERC.

It is important to note that the FERC in effect has already approved a tariff which permits billing to commence upon completion of the Alaskan Northwest, Foothills, and lower 48 segments, but prior to completion of the plant. The proposed waiver further divides the Alaskan Northwest and Foothills segments for billing commencement purposes. It is also important to note that the proposed waiver would not eliminate the authority of either the U.S. or Canadian government to certify that completion and commissioning of each individual segment has occurred.

a. Risk Of Non-Completion Of Any One Segment

It is extremely unlikely that any segment would be completed and commissioned but another not be completed and commissioned. First, the project sponsors and regulatory authorities will assure coordinated construction. FERC Order 31-B states that: "The Commission expects that U.S. and Canadian monitoring authorities will be doing everything in their power to ensure that all facilities associated with delivery of Prudhoe Bay are completed

simultaneously and that gas will begin to flow immediately upon their completion. The Commission expects to use its authority to facilitate attainment of that objective whenever possible". (Order 31-B at 69). In addition, "the various controls and oversight authority granted to the Federal Inspector encourage coordination and timely commencement of service." (Order 31 at 161); second, the most difficult portions of the project will be constructed first; third, the U.S. sponsors will not receive a return of or on equity until the entire system is completed and gas deliveries commence; fourth, anything but simultaneous construction would result in unnecessary carrying costs on money; and finally, no charges can be made before the target operation date, which will be established by the FERC as set forth in the President's proposed waiver.

b. Sponsor/Lender Risks

No charges can be assessed for any single one of the three segments until it is completed and commissioned. Thus, investors in such a segment would bear the loss associated with its non-completion. Consumers would pay the minimum bill for any completed and commissioned U.S. segment only after the target operation date and/or the full cost of service for the completed and commissioned Canadian segment, also only after such target operation date. If none of the three segments is completed and commissioned, the tariff does not operate, and consumers pay nothing.

Only when the entire system is completed and operating and consumers begin to receive Alaskan gas can Alaskan Northwest begin

to earn a return of and on the equity it invests in the project. Thus, Alaskan Northwest and the producers' equity will remain at risk until gas flows and thereafter depending on the cause and extent of any service interruptions.

c. Consumer Cost

While the proposed waiver could require consumers to pay some of the costs of a portion of the entire system pending the delivery of gas, the average residential consumer would pay only \$.32, \$.80, or \$.98 per month after the target operation date depending on which segment was not completed. The important point to remember, however, is that costs are being recovered currently thereby eliminating carrying charges that otherwise would be capitalized and paid for by consumers in rates over the life of the project. The FERC has recognized that this form of minimum bill actually reduces the finance charges to be borne by consumers when service commences. (Order 31 at 161).

d. Canadian Considerations

In May 1980, the National Energy Board of Canada, after extensive review and formal proceedings, found that a tariff would be needed in Canada which would allow the Canadian companies to charge their full cost of service when the Canadian segment was completed. The National Energy Board took this action before it approved the pre-build construction of a portion of the Canadian segment and related gas exports in order to ensure that the entire Canadian segment (500 miles of pre-build and 1500 miles of the remainder) could be financed and completed.

The U.S. government assured Canada that the entire project would be built and that the U.S. would permit the Canadian sponsors to charge for its segment when completed in exchange for the commitment by Canada to pre-build part of the system and deliver additional quantities of Canadian natural gas to the U.S. On July 18, 1980, President Carter sent a letter to Prime Minister Trudeau which said that the U.S. government remains committed to the project, that the U.S. government is satisfied the ANGTS will be completed, and that the administration would initiate action before the U.S. Congress to seek changes to laws that prohibit tariff payments from U.S. consumers to the Canadian sponsor upon completion of the Canadian segment of the ANGTS, but prior to the completion of the entire system. (See Appendix B).

e. Financing Considerations

A workable financing plan will require reducing the potential risks borne by the lenders to the maximum extent possible, given the magnitude of the capital required which, in turn, requires the greatest level of lender participation possible in terms of the number of lenders participating and the amount of debt provided by each lender. To attract such extensive participation mandates segmentation of the total system for purposes of billing commencement. For example, commercial banks and institutional lenders have legal and internal lending limits for any customer.

Additionally, lenders generally desire a varied portfolio to spread their risks among a variety of projects. The ANGTS sponsors are asking these lenders to commit an unusually large

amount of capital to a single undertaking. If the debt repayment is structured as though the ANGTS was three separate projects for debt repayment purposes, this should reduce the lenders' perception of risks to a level which may facilitate development of a private financing plan.

Finally, the recent volatile nature of both inflation and interest rates has changed drastically the approach taken by lenders in assessing the amount of loans that can be made to any project and the repayment schedules. Institutional lenders are now less willing to make long-term commitments than they were a few years ago given the present day market conditions.

f. Conclusion

The proposed waiver on billing commencement honors our commitment to Canada. Were it not for this commitment, Canada would not have proceeded with construction of the pre-build. Moreover, the consumer risk associated with this proposed waiver is minimal because it is so widely dispersed and because non-completion or delay in the simultaneous completion of the entire ANGTS is unlikely. The risk to be assumed by gas customers will be spread over literally millions of households and commercial and industrial establishments. Finally, consumers have more to lose if the ANGTS is not built. Over the next 25-30 years, U.S. consumers will pay more for their energy requirements if they have to use imported oil instead of Alaskan gas. The ANGTS will provide a reliable supply of energy to the lower 48 states which will not be subject to OPEC price increases or embargo.

B. Natural Gas Act

1. Evidentiary Hearing Requirements

The President proposes that Section 7(c)(1)(B) of the Natural Gas Act, Pub. L. No. 75-688, be waived to the extent it mandates the use of formal evidentiary hearings on ANGTS and related applications.

If Alaskan gas deliveries are to commence in late 1986, the process of obtaining a final certificate pursuant to Section 7 of the Natural Gas Act must not be unduly delayed.

This proposed waiver would remove any mandatory requirement that the FERC conduct any further formal evidentiary hearings on the ANGTS. However, the FERC would retain the discretion to order a formal evidentiary hearing if and when necessary.

No project in the Commission's history has been more closely scrutinized than the ANGTS. Three years of hearings were held before the Federal Power Commission prior to the President's 1977 Decision. One and one half years were spent in hearings, both in Canada and the U.S., before the final "prebuild" authorizations were issued. The rulemaking process that led to the development of the Incentive Rate of Return mechanism and the approval of the Alaskan Northwest tariff consumed two years. The FERC, the Office of the Federal Inspector, and their consultants have spent over one year reviewing the Alaskan pipeline cost estimate. In addition to this extensive regulatory review, the project received close scrutiny by a diverse group

of Federal agencies and the Congress pursuant to the Alaska Natural Gas Transportation Act of 1976. Every aspect of the project has been extensively examined.

Alaskan Northwest believes that the intense governmental review to date, the proven ability of the Commission to process effectively ANGTS matters through informal rulemaking procedures (notice and comment), and the inordinate delay that formal hearings would generate, support the grant of this waiver.

Approval of the proposed waiver would not relieve the FERC of its statutory responsibility under the Natural Gas Act to find that construction and operation of the remaining portions of the ANGTS would serve the public interest and is in the public convenience and necessity.

2. Regulatory Certainty

The President proposes that Sections 4, 5, 7, and 16 of the Natural Gas Act be waived to the extent that the FERC could otherwise change any rule or order to impair (i) recovery of actual operation or maintenance expenses, current taxes, and amounts necessary to service debt, including interest and scheduled retirement of debt, for the approved transportation system; or (ii) the recovery by purchasers of Alaskan gas of all costs related to the transportation of such gas pursuant to an approved tariff.

Sections 4, 5, 7, and 16 of the Natural Gas Act are the statutory authorities by which the Commission can suspend, investigate, establish, or modify the rates charged by Alaskan Northwest or the costs flowed through by the shippers to their customers.

The terms of Alaskan Northwest's cost recovery and that of the shippers will be finalized when the FERC issues its final certificates. Sections 4, 5, 7 and 16 of the Natural Gas Act could permit the Commission subsequently to modify the terms of the certificate in a manner which could impair the ability of Alaskan Northwest and/or the shippers to meet their financial obligations.

This proposed waiver would ensure the ability of the sponsors to maintain debt service and the shippers to pass-through their costs by limiting the authority of the FERC to change project and shipper tariffs after initial FERC approval in a manner that would impair the maintenance of debt service or preclude the recovery by shippers of any costs associated with the transportation of Alaskan gas. This does not mean that actual expenses would no longer be subject to continuing FERC review for prudence. Rather it only assures that there will be no impairment of debt service.

The cost recovery mechanisms for Alaskan Northwest and the shippers are the tariffs approved by the FERC and the Canadian National Energy Board pursuant to which the transportation companies charge the shippers for transportation service and the shippers, in turn, charge their customers for all ANGTS costs, including charges under the Foothills and lower 48 sponsor tariffs. As the Commission found in its Orders 31 and 31-B these tariffs are the "economic lifeline of the project." Because of the extraordinary risks attendant to the project and the enormous amount of financing needed, lenders will require satisfaction that, once approved by the FERC, the tariffs will not be subject

to future regulatory action which would impair the recovery of debt. This could occur if the FERC was to limit the payments to Alaskan Northwest by the shippers or to limit the passthrough of shipper costs associated with the project to their respective customers.

The FERC has attempted to provide as much regulatory certainty as possible by approving a tariff that, in the event of a service interruption, would in all events assure a stream of revenues sufficient to service debt and pay operation and maintenance expenses and taxes. However, the FERC recognizes that it could be legally possible for a future Commission to modify this tariff. In a letter dated August 18, 1981 to the Honorable Philip R. Sharp, Chairman of the Subcommittee on Fossil and Synthetic Fuels, Committee on Energy and Commerce, U.S. House of Representatives, and the Honorable Clarence J. Brown, Ranking Minority member, Subcommittee on Fossil and Synthetic Fuels, Committee on Energy and Commerce U.S. House of Representatives, the General Counsel of the FERC has written that both he and the FERC Chairman agree with the assessment that potential lenders to the ANGTS need greater assurances on the matter of regulatory certainty than they have been supplied to date and that, under present law, this assurance cannot be provided by the FERC.

This proposed waiver is limited in scope in order to preserve a balance between the assurance of pipeline revenue recovery vital to lenders and the statutory obligation of the FERC to assure just and reasonable rates. This waiver would only prevent changes to

the tariffs which would impair debt service for the ANGTS or preclude the recovery by shippers of costs associated with the transportation of Alaskan gas. Nothing in this waiver alters the nature and extent of the FERC responsibilities under the Natural Gas Act in reviewing the tariffs, as part of its certification process, to ensure that such tariffs are "just and reasonable" and in the public interest.

3. Status of Alaskan Northwest

The President has proposed a waiver of Sections 1(b) and 2(b) of the Natural Gas Act, Pub. L. No. 75-688, to the extent necessary to permit Alaskan Northwest and ANGTS shippers to be deemed natural gas companies within the meaning of the Act upon their acceptance of FERC certificates.

Section 1(b) of the Natural Gas Act states that "[t]he provisions of this act shall apply to the transportation of natural gas in interstate commerce . . . and to natural-gas companies engaged in such transportation" This section delineates the scope of activities which are subject to regulation under the Natural Gas Act. Section 2(6) defines a "natural gas company" as "a person engaged in the transportation of natural gas in interstate commerce"

Since neither Alaskan Northwest nor the shippers will physically transport Alaskan gas until completion and actual operation of the ANGTS, they may not be considered a "natural gas company" within the meaning of the Natural Gas Act, and therefore -- absent the waiver of these provisions of the Natural Gas Act --

would not qualify to collect charges under their FERC approved tariffs until gas actually begins to flow through the Alaskan Segment. To permit Alaskan Northwest to charge the minimum bill when the Alaskan pipeline segment or the conditioning facility is completed and commissioned, Sections 1(b) and 2(6) must be waived to the extent that they interpose a legal basis for any conclusion other than that Alaskan Northwest and the shippers will be natural gas companies upon acceptance of final certificates.

4. Export and Import Authorization

The President proposes to waive Section 3 of the Natural Gas Act, Pub. L. No. 75-688, to the extent any further authorization would be required for the export of Alaskan gas into Canada and the import of such gas into the lower 48 states.

Section 3 of the Natural Gas Act requires government approval prior to the import or export of natural gas to or from the U.S.

This waiver would permit the export and import of Alaskan gas without obtaining approval pursuant to Section 3 of the Natural Gas Act. Inasmuch as the President has already approved the export of Alaskan gas to Canada and the import of Alaskan and Canadian gas to the U.S. associated with the project, further governmental approvals should not be required.

C. Energy Policy and Conservation Act

The President proposes that Section 103 of the Energy Policy and Conservation Act, Pub. L. No. 94-163, be waived to the extent

it would require further authorization for the export of Alaska gas into Canada and the import of such gas into the lower 48 states. Section 103 of the Energy Policy and Conservation Act requires government approval prior to the export of natural gas from the U.S.

This waiver would permit the import and export of Alaskan gas without obtaining approval pursuant to Section 103 of EPCA. Inasmuch as the President has already approved the export of Alaskan gas to Canada and the import of Alaskan and Canadian gas to the U.S. associated with the project, further governmental approvals are not necessary.

Conclusion

The ANGTS sponsors have worked diligently and ceaselessly over the last seven years to provide a transportation system to bring much needed natural gas from Alaska to the lower 48 states. The ANGTS can be built in a timely and cost-effective manner. The need for this vital transportation link is without question and its benefits are substantial. But time is critical.

Since Congressional approval of the President's Decision in 1977, the ANGTS sponsors both in Canada and the U.S. have spent approximately three-fourths of \$1 billion - all of which is at risk - in the design and engineering of the ANGTS. Large additional capital expenditures and commitments must be made in the coming months to purchase the necessary supplies, materials, and equipment to keep the project on schedule. The

Alaskan Northwest partnership cannot justify risking additional substantial sums of money to keep the project on schedule absent the unqualified support of Congress expressed through the approval of the waiver transmitted by the President.

Additionally, the capital markets are not limitless. Project delay results in increased capital costs. The projected total completed cost of the ANGTS is approaching the capacity of the worldwide capital markets successfully to fund the project. If Congress does not act on the waiver this session, the capital costs of the project will escalate even further and our ability to secure adequate funds to complete the ANGTS will be severely jeopardized. Thus, the next step lies before you and the decisions that you make in the next several weeks will determine whether the project sponsors both in the U.S. and Canada can move forward to develop a private financing plan and complete this critically needed project.

THE END

APPENDIX A

PUBLIC LAW 95-158 [H.J.RES. 621]; NOV. 8, 1977

ALASKA NATURAL GAS TRANSPORTATION
SYSTEM—APPROVAL

For Legislative History of Act, see p. 3313

Joint Resolution approving the Presidential decision on an Alaska natural gas transportation system, and for other purposes.

Alaska natural
gas
transportation
system.
Presidential
decision.
Congressional
approval.
15 USC 719f
note.
42 USC 4321
note.

Resolved by the Senate and House of Representatives of the United States of America in Congress assembled, That the House of Representatives and Senate approve the Presidential decision on an Alaska natural gas transportation system submitted to the Congress on September 22, 1977, and find that any environmental impact statements prepared relative to such system and submitted with the President's decision are in compliance with the Natural Environmental Policy Act of 1969.

Approved November 8, 1977.

LEGISLATIVE HISTORY:

HOUSE REPORTS: No. 95-739, pt. I (Comm. on Interior and Insular Affairs) and No. 95-739, pt. II (Comm. on Interstate and Foreign Commerce).
SENATE REPORT No. 95-567 accompanying S.J. Res. 82 (Comm. on Energy and Natural Resources).
CONGRESSIONAL RECORD, Vol. 123 (1977):
Nov. 2, considered and passed House and Senate, in lieu of S.J. Res. 82.
WEEKLY COMPILATION OF PRESIDENTIAL DOCUMENTS, Vol. 13, No. 46:
Nov. 8, Presidential statement.

APPENDIX B

JULY 18, 1980

Office of the White House Press Secretary

THE WHITE HOUSE

TEXT OF A LETTER FROM THE
PRESIDENT TO THE
PRIME MINISTER OF CANADA

July 18, 1980

Dear Mr. Prime Minister:

Since you last wrote to me in March, the United States Government has taken a number of major steps to ensure that the Alaska Natural Gas Transportation System is completed expeditiously.

Most significantly, the Department of Energy has acted to expedite the Alaskan project. The North Slope Producers and Alaskan segment Sponsors have signed a joint statement of intention on financing and a cooperative agreement to manage and fund continued design and engineering of the pipeline and conditioning plant. The Federal Energy Regulatory Commission recently has certified the Eastern and Western legs of the System.

The United States also stands ready to take appropriate additional steps necessary for completion of the ANGTS. For example, I recognize the reasonable concern of Canadian project sponsors that they be assured recovery of their investment in a timely manner if, once project construction is commenced, they proceed in good faith with completion of the Canadian portions of the project and the Alaskan segment is delayed. In this respect, they have asked that they be given confidence that they will be able to recover their cost from U.S. shippers once Canadian regulatory certification that the entire pipeline in Canada is prepared to commence service is secured. I accept the view of your government that such assurances are materially important to insure the financing of the Canadian portion of the system.

Existing U.S. law and regulatory practices may cast doubt on this matter. For this reason, and because I remain steadfastly of the view that the expeditious construction of the project remains in the mutual interests of both our countries, I would be prepared at the appropriate time to initiate action before the U.S. Congress to remove any impediment as may exist under present law to providing that desired confidence for the Canadian portion of the line.

Our government also appreciates the timely way in which you and Canada have taken steps to advance your side of this vital energy project. In view of this progress, I can assure you that the U.S. government not only remains committed to the project; I am able to state with confidence that the U.S. government now is satisfied that the entire Alaska Natural Gas Transportation System will be completed. The United States' energy requirements and the current unacceptable level of dependence on oil imports require that the project be completed without delay. Accordingly, I will take appropriate action directed at meeting the objective of completing the project

more

(OVER)

by the end of 1985. I trust these recent actions on our part provide your government with the assurances you need from us to enable you to complete the procedures in Canada that are required before commencement of construction on the prebuild sections of the pipeline.

In this time of growing uncertainty over energy supplies, the U.S. must tap its substantial Alaska gas reserves as soon as possible. The 26 trillion cubic feet of natural gas in Prudhoe Bay represent more than ten percent of the United States total proven reserves of natural gas. Our governments agreed in 1977 that the Alaska Natural Gas Transportation System was the most environmentally sound and mutually beneficial means for moving this resource to market. Access to gas from the Arctic regions of both countries is even more critical today as a means of reducing our dependence on imported petroleum.

Successful completion of this project will underscore once again the special character of cooperation on a broad range of issues that highlights the U.S./Canadian relationship.

I look forward to continuing to work with you to make this vital energy system a reality.

Sincerely,

JIMMY CARTER

• • • • •

APPENDIX C

96TH CONGRESS
2D SESSION

S. CON. RES. 104

CONCURRENT RESOLUTION

Whereas, the Alaska Natural Gas Transportation System is a critically important energy project that will tap Alaska's North Slope natural gas reserves which constitute more than 10 percent of this Nation's entire proven natural gas reserves;

Whereas, the System, when complete will supply the United States with 5 percent of its annual natural gas demand, displacing over four hundred thousand barrels of oil, thereby greatly reducing this Nation's excessive dependence on foreign oil;

Whereas, the Congress has already expressed its overwhelming support for the System in approving by joint resolution the President's 1977 Decision on the Alaska Natural Gas Transportation System;

Whereas, a portion of the System known as prebuild can be constructed by the end of 1981 to bring Canadian gas to this Nation until the entire system is complete in 1985;

Whereas, prebuild will contribute to completion of the entire System by spreading demand for capital, labor and materials over several years, and will enable this Nation to obtain Canadian natural gas to displace two hundred thousand barrels of foreign oil a day;

Whereas, the Federal Energy Regulatory Commission has issued decisions granting certificates for the prebuild facilities in the United States;

Whereas, the sponsors of the Alaskan segment of the System and the North Slope natural gas producers have entered into an agreement to fund and manage jointly the design, engineering and cost estimation for the Alaskan segment and have made a joint Statement of Intention to work to develop a financing plan for the Alaskan segment with the object of completing construction by the end of 1985: Now, therefore, be it

1 *Resolved by the Senate (the House of Representatives*
2 *concurring),* That it is the sense of the Congress that the
3 System remains an essential part of securing this Nation's
4 energy future and, as such, enjoys the highest level of con-
5 gressional support for its expeditious construction and com-
6 pletion by the end of 1985.

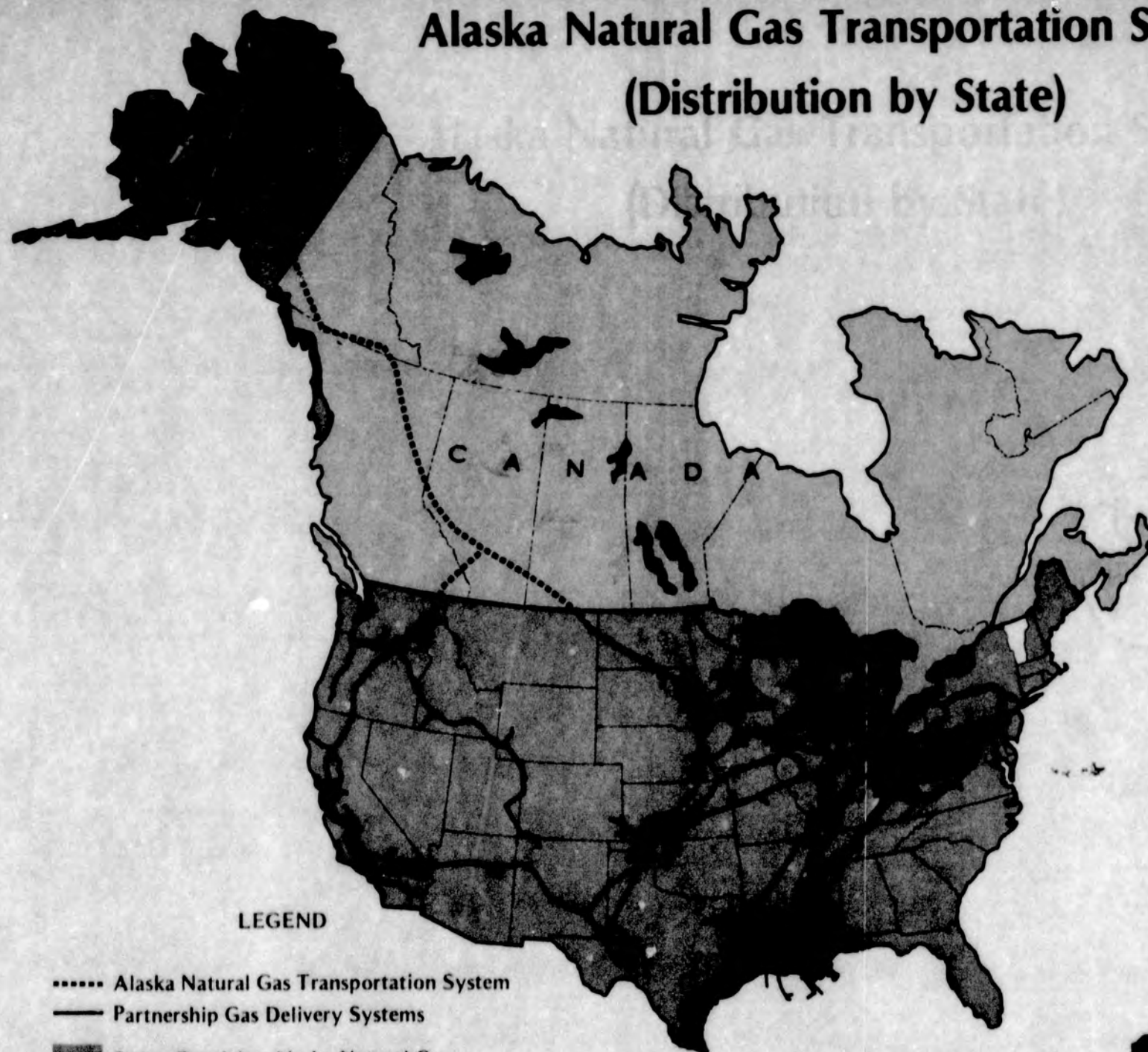
Passed the Senate June 27 (legislative day, June 12),
1980.

Attest:

Secretary.

APPENDIX D

Alaska Natural Gas Transportation System (Distribution by State)



LEGEND

- Alaska Natural Gas Transportation System
- Partnership Gas Delivery Systems
- States Receiving Alaska Natural Gas

APPENDIX E

THE DEMAND FOR ALASKAN NATURAL GAS

JULY 1981

A Report to:

NORTHWEST ALASKAN PIPELINE COMPANY

Prepared by:

**JENSEN ASSOCIATES, INC.
Boston Washington Geneva**

**84 State Street
Boston, Massachusetts 02109
Telephone: (617) 227-8115
Telex: 94 - 0057**

TABLE OF CONTENTS

<u>Chapter</u>		<u>Page</u>
	<u>EXECUTIVE SUMMARY</u>	vii
	Introduction	vii
	Summary and Conclusions	vii
I	<u>THE MARKET ENVIRONMENT FOR ALASKAN NATURAL GAS</u>	1
	The Evolution of Oil and Gas Markets during the Seventies	2
	The Likely Natural Gas Market Environment during the Eighties	6
II	<u>THE ROLE OF PRICE</u>	13
	The Outlook for Oil and Gas Prices	14
	International Oil Markets and OPEC	15
	The Crude Price Projections	22
	Oil Prices for the U.S.A.	23
	Product Prices	25
III	<u>FORECAST OF LOWER 48 STATES GAS SUPPLY</u>	27
	Summary Forecast	27
	Lower 48 States Production	27
	Canadian Gas Imports	42
	Mexican Gas Imports	43
	Liquefied Natural Gas (LNG) Imports	44

TABLE OF CONTENTS (Continued)

<u>Chapter</u>		<u>Page</u>
	Unconventional Production	44
	Synthetic Natural Gas (SNG)	45
	Alaskan Pipeline Gas	46
IV	<u>THE DEMAND FOR NATURAL GAS</u>	47
	Residential/Commercial Demand	47
	Industrial Demands for Natural Gas	54
	Gas Demand in the Electric Utility Sector	58
V	<u>SUPPLY/DEMAND BALANCE</u>	61
	The Impact of Early Deregulation	63

LIST OF TABLES

<u>Number</u>		<u>Page</u>
1	FORECASTS OF REFINERS' ACQUISITION COST OF CRUDE OIL	xi
2	SUPPLY AND DEMAND FOR U.S. NATURAL GAS	xii
III-1	LOWER 48 STATES TOTAL GAS SUPPLY FORECAST	28
III-2	NATURAL GAS PROVED RESERVES AND PRODUCTION, LOWER 48 STATES	29
III-3	NATURAL GAS RESERVES/PRODUCTION RATIOS, LOWER 48 STATES	32
III-4	GAS WELL COMPLETIONS BY TYPES, LOWER 48 STATES	33
III-5	CEILING PRICES FOR "NEW" VINTAGE NATURAL GAS	34
III-6	AVERAGE WELLHEAD PRICE FOR NATURAL GAS, UNITED STATES	35
III-7	GAS AND OIL WELL COMPLETION FOOTAGE, LOWER 48 STATES	36
IV-1	LOWER 48 STATES DEMAND FOR NATURAL GAS	48
IV-2	U.S. AVERAGE NATURAL GAS PRICES	50
IV-3	U.S. AVERAGE RESIDENTIAL ENERGY COSTS	52
IV-4	RESIDENTIAL AND COMMERCIAL GAS DEMAND	53
IV-5	TOTAL U.S. INDUSTRIAL FUEL SWITCHING	55
IV-6	INDUSTRIAL NATURAL GAS DEMAND	59
V-1	SUPPLY AND DEMAND FOR U.S. NATURAL GAS	62

LIST OF FIGURES

<u>Number</u>		<u>Page</u>
1	1987 ROLL-IN CAPACITY OF U.S. NATURAL GAS MARKETS	xiii
I-1	THE EVOLUTION OF GAS/OIL MARKETS	3
I-2	THE EVOLUTION OF GAS/OIL MARKETS DURING THE 1980s	9
II-1	GAS WELLHEAD PRICES COMPARED WITH REFINER'S CRUDE ACQUISITION COST	16
II-2	ACTUAL AND ALLOWABLE CRUDE OUTPUT AS % OF MAXIMUM SUSTAINABLE PHYSICAL CAPACITY	18
II-3	CRUDE PRICES VS OPEC CAPACITY OPERATION	20
II-4	PROJECTIONS OF THE DELIVERED PRICE OF OPEC'S MARKER CRUDE	24
III-1	NATURAL GAS PRODUCTION AND RESERVE ADDITIONS, LOWER 48 STATES	30
III-2	GAS AND OIL WELL COMPLETION FOOTAGE, LOWER 48 STATES	37
III-3	NATURAL GAS FINDING RATES, LOWER 48 STATES	39
III-4	NATURAL GAS RESERVES/PRODUCTION RATIO, LOWER 48 STATES	41
V-1	GAS SUPPLY/DEMAND BALANCES BY USER TYPES	64

EXECUTIVE SUMMARY

Introduction

In September 1979, Jensen Associates, Inc. completed a study of "The Market Outlook for Alaskan Natural Gas" for Northwest Alaskan Pipeline Company. We have been asked by Northwest Alaska to review the marketability of Alaskan natural gas in greater detail and to update our conclusions in the light of events which have transpired since the first report. This study--like the previous one--was commissioned to review the purely commercial outlook for Alaskan gas, rather than to deal with the many aspects of national energy policy which necessarily influenced the decision to proceed with the pipeline. In focusing on the commercial marketability, the emphasis has been upon the likely gas market environment during the construction and early operation of the pipeline. Thus, its time frame is the decade of the 1980s.

Summary and Conclusions

The market environment for natural gas in the United States continues to undergo profound changes as demand, supply, price and the prospects for competitive energy sources all respond to the upheavals in energy markets which were set in motion throughout the world during the 1970s. By 1987, when Alaskan gas will be available, we expect that the decline of conventional Lower 48 (L48) gas supplies will have created a strong demand for supplementary gas volumes, if gas is not to lose market share to imported oil. In an environment of rising real prices for oil--which we believe is the most likely expectation for long-term price trends--the price structure for Alaskan gas will look increasingly favorable compared both to oil and to those alternative gas supplies whose prices escalate with oil.

We believe that Alaskan gas is marketable, not only under the rising long-term price increase scenario--which we term our "least unlikely" forecast--but also under a more conservative price projection which we have utilized in this study to test market response.

The underlying driving force which will be most influential in creating increased demand for gas in general, and a market for Alaskan supplies in particular, is an increase in real prices for world oil. A major portion of existing U.S. industrial and power generation plant capacity is designed for oil and/or gas firing and is not readily convertible to coal or other fuels. Thus, rising oil prices quickly shift demand to gas. In addition, prices of most supplementary gas supplies--such as Canadian, Mexican or LNG--are being linked to oil. Rising real prices for oil thus make Alaskan gas--without such linkage--increasingly attractive relative to alternate supplies.

Our "least unlikely" crude price forecast calls for a 60 percent increase in real crude oil prices between early 1981 and 1987 when the

Alaskan gas is scheduled to flow. Under such an oil price scenario, Alaskan gas--priced in the middle of its expected range--would be cheaper than oil-indexed imports from Canada, Mexico and Algeria by 1989.

Early 1981 has seen a marked shift in the outlook for world oil supplies and prices. The successful weathering by world oil markets of the Iraq-Iran crisis, together with unexpectedly high reductions in world oil--and OPEC oil--demand has forced many oil economists to moderate their projections. Most forecasters have lowered their near-term oil price estimates and some have substantially lowered their long-term estimates as well. We at Jensen Associates have also reduced our price expectations for the near-term and adjusted our longer-term "lower-bound" price scenario. But we are not convinced that the conditions necessary for the lower-bound forecast--continuing overhang of surplus oil supply within OPEC, and an absence of disruptive military or political events in the Middle East--will persist throughout the 1980s. We thus continue to regard the lower-bound case as less probable. We view a continuation of the world oil pricing patterns which prevailed during the 1970s as more probable. These call for at least one disruptive event and subsequent price increase between now and the time the Alaskan gas flows.

Roughly two-thirds of the time since early 1973, world oil supply has been in balance or in surplus, with a tendency toward stable or declining real oil prices. Yet, 80 percent of the oil price increase during the period occurred during those times when events in the Middle East upset world oil balances. The majority of the time there may have been--as there may be now--a natural tendency to ignore the dominant "crisis" element in world oil price formation.

Our least unlikely price projection, together with our less probable lower-bound case, are shown in Table 1. The least unlikely forecast is, of necessity, illustrative since one cannot predict the timing of disruptive events; for purposes of this forecast, we have arbitrarily projected a disruption in 1984, with price formation before and after the event forecast by analogy to the 1973/1974 and 1979/1980 disruptions. Our less probable lower-bound case has weakening real prices until the end of 1982, followed by the operation of the OPEC long-range strategy formula thereafter.

Much of our marketability analysis has been focused on the interaction of upper-bound Alaskan gas price estimates with lower-bound world oil price projections, in order to test the market under the least favorable combination of circumstances. World oil prices have already risen substantially since the passage of the Natural Gas Policy Act (NGPA) in November 1978 and crude oil price deregulation in January 1981 placed further upward price pressures on competitive oil prices.

While oil prices have risen, gas pricing, under the terms of the Natural Gas Policy Act of 1978, is to be controlled until new gas deregulation in 1985, thus creating strong pressures to drive dual-fueled demand

to gas and create incentives for new customer growth and gas conversions. Thus, we see a growing demand for gas, despite major conservation-induced energy savings.

We do not see as easy an expansion of gas supply. Lower 48 production should continue to decline despite accelerated drilling activity. The addition of supplementary sources will be required to attempt to maintain supply levels. The supplements to maintain supply levels are apt to be costly, as increasingly, prices for gas imports from Canada, Mexico and LNG projects will be indexed to rising world oil prices.

The outlook for demand until 1985 is likely to be for a return of some of the excess demand conditions which first faced the gas industry from 1971-1977. New gas deregulation in 1985 will cause some price correction, and some loss of load, but a market will still remain for rolled-in Alaskan gas when it comes on line in 1987. Our estimates of gas demand together with supply (in the most severe, lower-bound oil price case) is shown in Table 2.

In the Natural Gas Policy Act, Congress granted Alaskan gas the right to rolled-in treatment for ratemaking purposes. This was designed to permit price-controlled old gas (which will continue long after 1985 new gas deregulation) to cross-subsidize any portion of the price of Alaskan gas over and above market clearing price levels. In a high oil price scenario, Alaskan gas quickly becomes competitive on the margin, as real oil prices overtake the initially higher-priced Alaskan gas. In our least unlikely combination of oil and gas prices, Alaskan gas requires little roll-in treatment during the early years to be marketable.

However, with projected Alaskan gas prices at the upper bound, and oil price expectations at the lower bound, Alaskan gas must rely--in the early years, at least--on the rolled-in treatment which Congress granted it in the NGPA. Assuming this relatively unfavorable combination of higher-bound Alaskan gas prices and lower-bound oil prices, we estimate that the 1987 market will have 25 percent of total U.S. gas supply still regulated below market clearing levels, amounting to a roll-in capacity of \$11.7 billion. This is illustrated in Figure 1. Other supplementary gas supplies, priced above clearing levels, will utilize a portion of this capacity, but most of it remains to accommodate the Alaskan gas and to provide a potential for "flyup"--the rapid market and contractual escalation of deregulated new gas prices in 1985.

It is possible that the gas pipeline industry, through its contracting practices between now and 1985, can lock in enough deregulated gas price escalation to absorb the roll-in capacity in this lower-bound case and make it difficult to accommodate the Alaskan gas. We sense a growing awareness of this problem in the industry with greater emphasis on supply planning and on market protection contract clauses. We therefore believe the problem is manageable if dealt with in time.

In summary, we believe that a commercial market for Alaskan gas will exist in 1987. In our least unlikely world oil price scenario, Alaskan gas will increasingly be competitive with alternate gas supplies, which will be largely linked to oil. A combination of upper-bound Alaskan gas prices and lower-bound oil prices will require reliance on roll-in capacity, but enough capacity should exist to accommodate it.

TABLE 1

**FORECASTS OF REFINERS' ACQUISITION COST OF CRUDE OIL
(1980 \$/barrel)**

	<u>1981</u>	<u>1985</u>	<u>1987</u>	<u>1990</u>
Least Unlikely Case ^a	\$35.21	\$59.30	\$57.60	\$66.42
Lower-Bound Case	\$35.21	\$36.19	\$38.43	\$42.01

^a Assumes a disruption in 1984 with a sharp price increase followed by a period of market weakness.

Source: Jensen Associates, Inc.

TABLE 2

SUPPLY AND DEMAND FOR U.S. NATURAL GAS

1980 - 1990

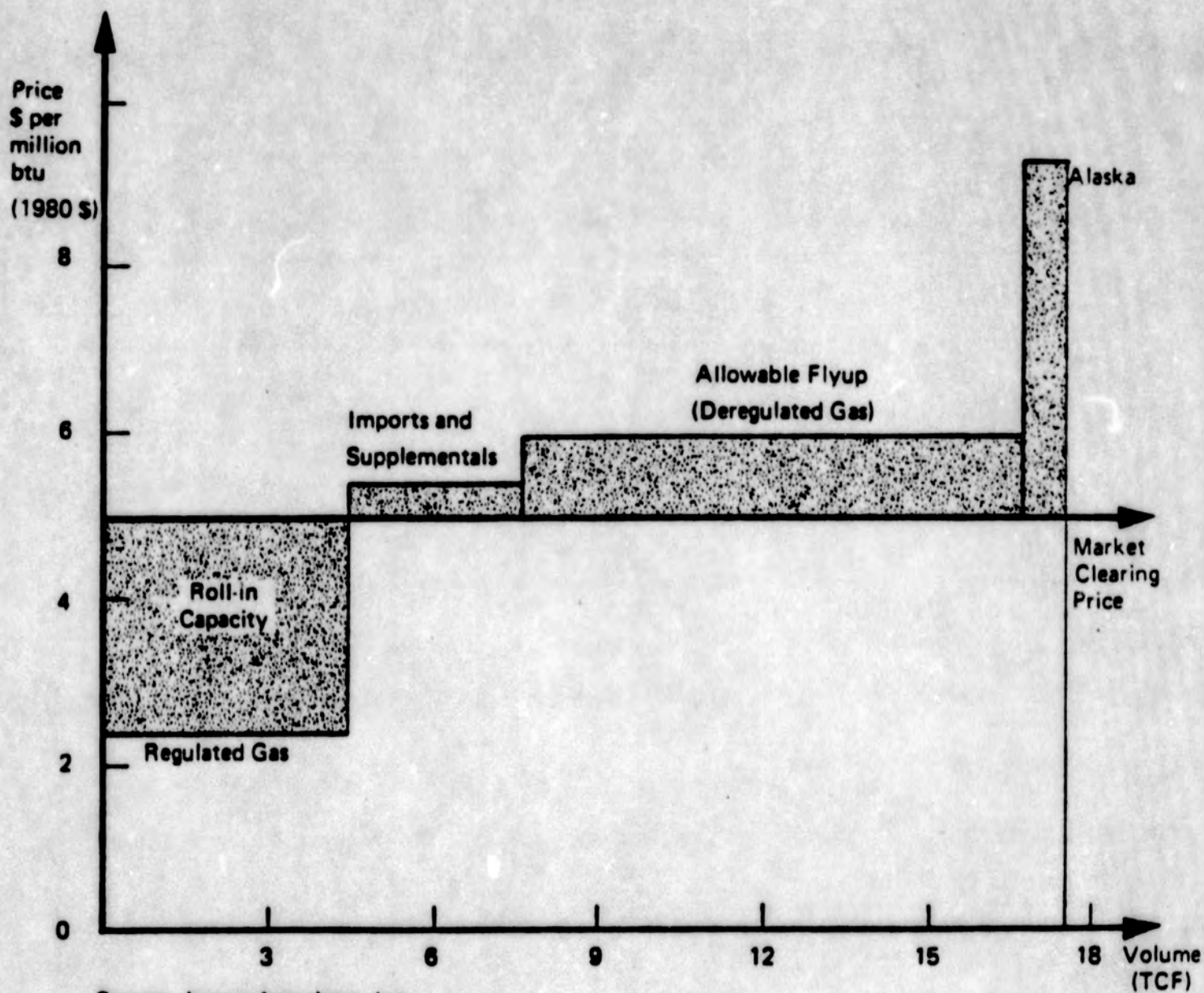
(Trillion cubic feet)

	Estimated <u>1980</u>	Forecast	
		<u>1985</u>	<u>1990^a</u>
Total Demand	20.5	22.5	18.4
Total Expected Supply (Excluding Alaska)	20.5	18.8	17.7
<u>Shortfall</u>			
Without Alaska	--	3.8	0.7
With Alaska	--	3.8	0

^a The 1990 demand forecast is based on a cleared market for natural gas.

Source: Jensen Associates, Inc.
U.S. Department of Energy

FIGURE 1
1987 ROLL-IN CAPACITY OF U.S. NATURAL GAS MARKETS
 (Based on Lower Bound Crude Price
 and
 Upper Bound Alaskan Price)



Source: Jensen Associates, Inc.

I. THE MARKET ENVIRONMENT FOR ALASKAN NATURAL GAS

Energy markets have been changing rapidly during 1981. The natural gas shortages of 1976/1977 have been replaced by a persistent "gas bubble;" the chaotic 1979 world oil markets which followed the Iranian Revolution have been supplanted by an "oil glut" with visible evidence of strain within OPEC. Energy price signals now often point downward, rather than consistently upwards as they have in the recent past. It is tempting to believe--as the popular and business press frequently observe--that world energy problems are on their way to solution and that complex and expensive energy supply options from nuclear power, to synfuels, to LNG, or to Alaskan gas may no longer be commercially justified.

We disagree with this hypothesis. The energy markets of 1987, when the Alaskan gas will be available to the Lower 48, are likely to be far different from the energy markets of 1981. The improvements in natural gas and oil balances have come predominantly from the demand side, partly through demonstrated levels of conservation which are much larger than most forecasters would have anticipated, but also through general weakness in economic activity both in the U.S. and the rest of the OECD. Improvements in energy supply for the most part have been disappointing, certainly, relative to expectations for supply five to ten years ago.

To the extent that portions of the U.S. natural gas and world oil surpluses are recession-induced, any pickup in economic activity threatens to restore some of the tighter energy market conditions which previously prevailed. This, in our view, is a much more likely expectation than a persistence of gas and oil surpluses through the latter part of the decade.

There are three critical elements determining the marketability of Alaskan natural gas. They are:

- the evolution of natural gas demand in the U.S. within the context of total U.S. energy market balances;
- the expectation for alternative gas supplies, both from traditional Lower 48 sources, as well as from imports and the gas supplements;
- and--since on the margin most gas competes with oil--the outlook for world oil price levels.

Our analysis suggests that gas demand will rise between now and 1985, as gas prices remain price-regulated under the NGPA and oil prices are deregulated. New gas deregulation after 1985, however, will diminish the comparative price advantage of gas. As a consequence, the price-sensitive demand for gas will shift to other fuels, thereby eliminating the excess demand for gas.

The outlook for gas supply, in our view, is for a continuing decline in Lower 48 production, with a resulting need for supplementary gas supplies to meet demand.

Rising real oil price levels have two interrelated effects. They increase the relative demand for gas compared to higher-priced oil; and they render most other supplementary supplies--which are for the most part price-indexed to oil--increasingly costly relative to Alaskan gas. Higher oil prices--as in our least unlikely oil price case--quickly make Alaskan gas competitive in its own right. In a more conservative lower-bound oil price projection, this competitive crossover point is delayed and Alaskan gas must resort in the early years to the roll-in treatment which Congress granted it in the NGPA.

The Evolution of Oil and Gas Markets during the Seventies

The commercial market for natural gas during the 1970s has been extremely complex. Projections and estimates made by normally knowledgeable observers have been frequently overtaken by events in a matter of months. We believe that the turmoil in natural gas markets is more likely to increase than to decrease during the 1980s, as the supply and price of both oil and gas are heavily affected by regulatory and political pressures, as well as the operation of the usual market forces.

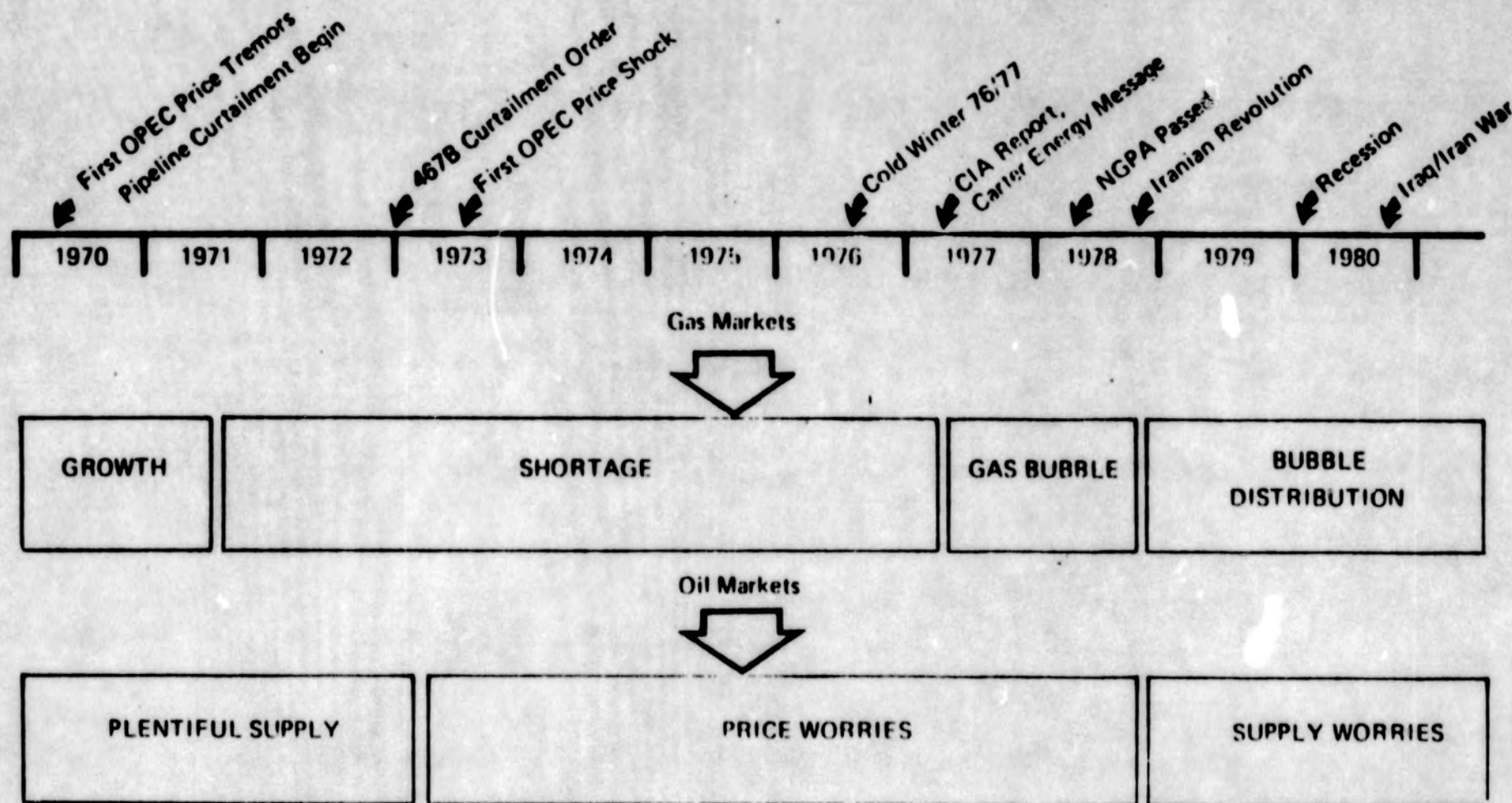
Jensen Associates identifies four major gas market environments during the seventies which we call the "growth," "shortage," "gas bubble," and "bubble distribution" periods. Figure I-1 depicts the chronological evolution of these markets over the last decade.

From the end of World War II to 1971, natural gas was the fastest growing energy source in the United States. When the 1954 Phillips decision of the U.S. Supreme Court placed interstate gas wellhead prices under Federal Power Commission control, gas prices were no longer influenced by changes in unregulated coal and oil prices. As a result, gas--in a period when supply was not perceived as limiting--carved out substantial increases in market share at the expense of competitive fuels. By 1971, the major interstate natural gas pipelines were no longer able to satisfy the growing demand for natural gas and an era of interstate natural gas pipeline curtailments began.

The growth period for natural gas, which effectively ended with the first interstate pipeline curtailments in 1971, was a period when relatively little concern was expressed about the availability or pricing of oil. Indeed, there was often little recognition of the fact that most oil on the margin had to be imported.

The natural gas shortage period, from 1971-1977, was an era when regulation sought to restrain the demand for natural gas to its clearly limited supply. This was accomplished by moratoriums on the attachment of new

FIGURE I-1
THE EVOLUTION OF GAS/OIL MARKETS



customers and by end-use curtailment mechanisms, which allocated shortages primarily among large industrial and power generation customers.

Perceptions about international oil supply and price changed substantially during this period. The Arab oil embargo of 1973/1974 led to a quadrupling of international oil prices by OPEC and public attention tended to focus on price rather than supply. It was common to characterize OPEC as a cartel which would ultimately break up and bring prices back down to "reasonable levels." A little recognized by-product of the natural gas curtailment priority system was that most of the curtailed gas demand in fact switched to oil. Our figures suggest that between 1972, the peak year of gas deliveries, and the passage of the NGPA in 1978, 76 percent of the fuel switching from gas was to oil, which on the margin had to be imported.

During the gas shortage period, the large overhang of excess gas demand at prices well below oil led gas suppliers to try to make up the shortages with alternative supplies, almost without regard to price. The fact that any new supply--such as comparatively high-priced SNG made from oil feedstocks--could be averaged with price-controlled supplies and still keep prices to the customer below market clearing levels, led to the phenomenon of rolled-in pricing, where high-cost gas could be averaged with price-controlled gas without loss of market share.

The logic surrounding the Natural Gas Policy Act of 1978 was born out of the shortage period. The winter of 1976/1977 had been abnormally cold, particularly in the upper Midwest. For a time it appeared that the worst gas shortage fears had finally materialized, with a cut-off of gas to industry and schools resulting from a seeming breakdown of supply. In retrospect, the winter of 1976/1977 appears to have been more a severe winter peak-demand problem that the system was no longer able to handle, than the chronic annual shortage which was increasingly anticipated during the shortage period. To enhance domestic supply, the NGPA liberalized price controls on many categories of gas, pointing towards deregulation of new gas by 1985. It did attempt to eliminate the dual market between intrastate and interstate gas by applying price controls to new intrastate gas for the first time and making the movement of gas from intrastate to interstate markets more flexible. The Act also introduced incremental pricing, which was in part designed to prevent undisciplined price behavior--through roll-in--in a tight market by threatening loss of industrial load. However, because of the desirability of Alaskan natural gas, that source was given a special exemption from incremental pricing, allowing it to be rolled-in.

By the time the Natural Gas Policy Act became law in November 1978, natural gas markets were already nearing balance, and talk of the "gas bubble" became common. In retrospect, it appears that conservation, principally by industrial users but also by residential and commercial customers, was much greater than most observers had anticipated. One of the major contributions to the bubble was the very substantial conservation which occurred in the intrastate market. Although gas production levels went

down, demand levels dropped even further, creating a surplus from the demand side which was potentially available for the interstate market.

Our analyses suggest that at the time of the passage of the NGPA, no more than 1 trillion cubic feet (tcf) of the 2.3 tcf drop in industrial demand had switched out of natural gas into alternate fuels over the 1972-1978 period. Conservation accounted for the remainder of the net demand effect. Furthermore, in late 1978, a surplus of comparable size existed in the intrastate gas market as conservation had reduced demand below available supply and producers were reluctant to commit the surpluses to regulated interstate pipelines.

Our analysis suggests that in late 1978, the market was near balance and might well have cleared quickly had the NGPA simply provided for flexibility in moving gas from intrastate to interstate markets without all of the NGPA's complex pricing features. The simultaneous occurrence of the Iranian revolution and subsequent increase in world oil prices, however, has recreated a situation in which regulated gas prices fail to track competitive oil market prices.

The easing of the gas shortage and the emergence of the gas bubble coincided with growing concern about international oil. Oil concerns from 1973-1977 were largely about prices based on the view of OPEC as a price-fixing cartel which should be "broken up." President Carter's energy message in April 1977 publicly raised the possibility of oil shortages as well. It called upon an analysis by the Central Intelligence Agency which argued that deteriorating Russian oil supplies would put the Russians into competition for Middle East oil by the early to mid 1980s and create the possibility of physical shortages. Thus, attention shifted over the period of 1973-1977 from cartel-oriented price worries to genuine concern about physical supply. Ironically enough, by the time the NGPA was passed, its implied concern about excess gas demand and the threatened use of oil competition to discipline gas prices had largely been replaced by concern over the management of oil imports.

Among the measures which the Department of Energy (DOE) initiated to deal with oil shortages was the Order 30 program. This was designed to put surpluses of natural gas--the gas bubble--under interstate boilers to back out imported oil. Thus, where oil had been used as an agent to control excess gas demand during the gas shortage period, the gas bubble was being used as a device to control oil imports.

During 1979, while the international oil spot market was rising rapidly and the official OPEC prices rose two-and-one-half fold, we at Jensen Associates believed that the U.S. was entering a fourth market period we called "oil crunch." We anticipated that the rapidly emerging disparity between oil and regulated gas prices would cause a surge of conversions to natural gas, absorb the bubble, and recreate the conditions for shortage. In our forecast of natural gas markets for Northwest Alaska in 1979, we described this "crunch" phenomenon as creating a substantial,

strong future outlook for gas demand, although the hard statistical information to demonstrate that it was occurring was not yet available.

From the vantage point of December 1980, it now appears that the gas surplus has remained with us and the "crunch" phenomenon anticipated by Jensen Associates in mid 1979 has not occurred as previously expected. A recap of the developments in the market from 1978-1980 suggests that the onset of the recession had a significant effect in holding demand below capacity levels. While the recession, as measured by changes in the Gross National Product, was slow to make its appearance during 1979, many energy-intensive industries such as cement, steel, and refining were selectively hit early. This caused a reduction in total industrial energy demand below what might have been expected on the basis of economic conditions alone. Thus, we have changed our designation of the period from 1978-1980 from "oil crunch" to "bubble distribution."

Examination of the figures for the period from 1978-1980 suggests that, indeed, a major shift in the bubble from the intrastate to the interstate market took place. Since intrastate markets were limiting production levels prior to the NGPA, gas which would normally have been produced for intrastate customers was cut back. The passage of the NGPA permitted this gas, which previously would have gone intrastate, to flow to interstate markets giving the appearance of a supply improvement. This production increase was due less to basic supply improvement than it was to the increased flexibility to move gas outside the producing state. We estimate that between 1978 and 1980, total gas demand actually supplied (on a weather normalized basis) increased by slightly over 1.5 tcf. Approximately a quarter of the increase occurred in residential, commercial and high-value industrial markets. More than half of this high-value gas demand increase occurred in the Northeast where the contrast between the prices of traditional oil fuels and price-controlled natural gas was the most dramatic. This increase, we believe, was truly a "crunch" effect. However, three-quarters of the increase in demand occurred in boiler fuel and power generation uses--principally in interstate markets--where curtailment-induced fuel switching was concentrated. This was the "bubble distribution" effect made possible by the more flexible intrastate/interstate gas transfer arrangements contained in the NGPA.

The Likely Natural Gas Market Environment during the Eighties

During the 1970s, the development of new natural gas market environments, which resulted from changing patterns of supply, demand, and pricing for oil and gas were sometimes surprising. Clearly, one cannot discount further surprises during the 1980s. Already, for example, 1981 has provided a largely unforeseen drop in world oil demand sufficient to reduce net requirements for OPEC oil to the lowest level since 1970, and to stimulate significant weakening of international oil prices. But many of the forces which will determine the market environment for Alaskan gas in 1987 are already in evidence. They suggest to us that energy markets in 1987

will be much different from energy markets of 1981, and that a commercial market will exist for Alaskan gas at that time.

Energy markets in mid 1981 are characterized by surplus--a persistent bubble in U.S. natural gas markets and a substantial international oil surplus. The oil surplus is the most recent development and one which has caught much of the industry by surprise. The world has weathered the Iraq-Iran war this past winter with no more than a minor flurry in the spot market in October/November, and emerged with evidence of a sizable market reaction to the price increases of 1979/1980. Free world oil demand this year might be no more than 46-47 million barrels per day, off about 3-4 million barrels per day from last year's levels. Net demand for OPEC oil could fall as low as 23 million barrels per day against an allowable OPEC capacity level of 30 million barrels per day. Total energy demand growth has fallen significantly below expectations and strong growth in both other energy sources and in non-OPEC oil have resulted in the sizable OPEC reduction.

In one view, this sudden change is more a reaction to faltering economic performance throughout the OECD than it is evidence of a new trend to deeper and more lasting demand response to higher price levels. World energy demand, and net demand on OPEC, both reacted to the sharp oil price increases of 1973/1974 only to resume a lower level of upward growth with an improvement in world economies in 1976. The nature of new increments of coal or nuclear capacity is that they are apt to be utilized first--as lowest in running cost--when total demand falters, thus leveraging oil demand downward in a recessionary year. But oil demand can readily return again as the economy strengthens. This pattern is being intensified during 1981 by the emergence of inventory liquidation of the excessively high world oil stocks which were built up in the market panic of 1979/1980. We look for a turnaround in OECD economic performance and in world oil demand by the early part of 1983, with a return of some supply insecurity and rising prices beyond that point.

We believe that the gas bubble will also begin to disappear as the U.S. economy develops some strength by 1983. Thus, the pattern which we foresee for 1983 and 1984--a return to conditions of excess gas demand--will characterize the middle years of the gas market before Alaskan gas flows to the Lower 48. The excess gas demand will be in response to the gas price controls retained under the NGPA, concurrent with domestic crude oil price deregulation (January 1981), which allowed prices to rise to international levels.

For gas, we have assumed that wellhead pricing will operate under the price constraints of the Natural Gas Policy Act through 1984. As presently envisioned, Section 102 gas--gas newly discovered since April 1977--will be deregulated, along with several other categories, and allowed to seek its own market level at that time. The original Congressional intent appears to have been to retain price controls on domestic natural gas while supply improvement was allowed to reduce the overhang of excess demand. The

complex regulated gas price trajectories were to intersect with competitive fuel levels, so that an orderly transition to deregulation could occur in 1985. Clearly, the price levels, which Congress may have expected to provide an orderly transition in 1978, are totally unrealistic in 1981 after the oil price increases of 1979. While U.S. gas prices rose during 1979 at an almost unprecedented average rate of 3.4 cents per million Btus per month, the refiners' acquisition cost of crude oil in the United States rose at 15.4 cents per million Btus per month. Even residual fuel oil, which suffered price weakness from gas competition in a number of sections of the country, rose an average of 6.3 cents per million Btus per month. Thus, the gas price trajectory in the NGPA clearly failed to track competitive fuel levels in 1979. In our view, it will continue to fail to track the likely price trajectory of refiner acquisition cost of crude oil during the early 1980s. That suggests a significant price readjustment may take place in 1985 upon new gas deregulation, unless the supply of gas was so large as to set its own internal market clearing price structure without regard to competition from oil. In our view, this is extremely unlikely.

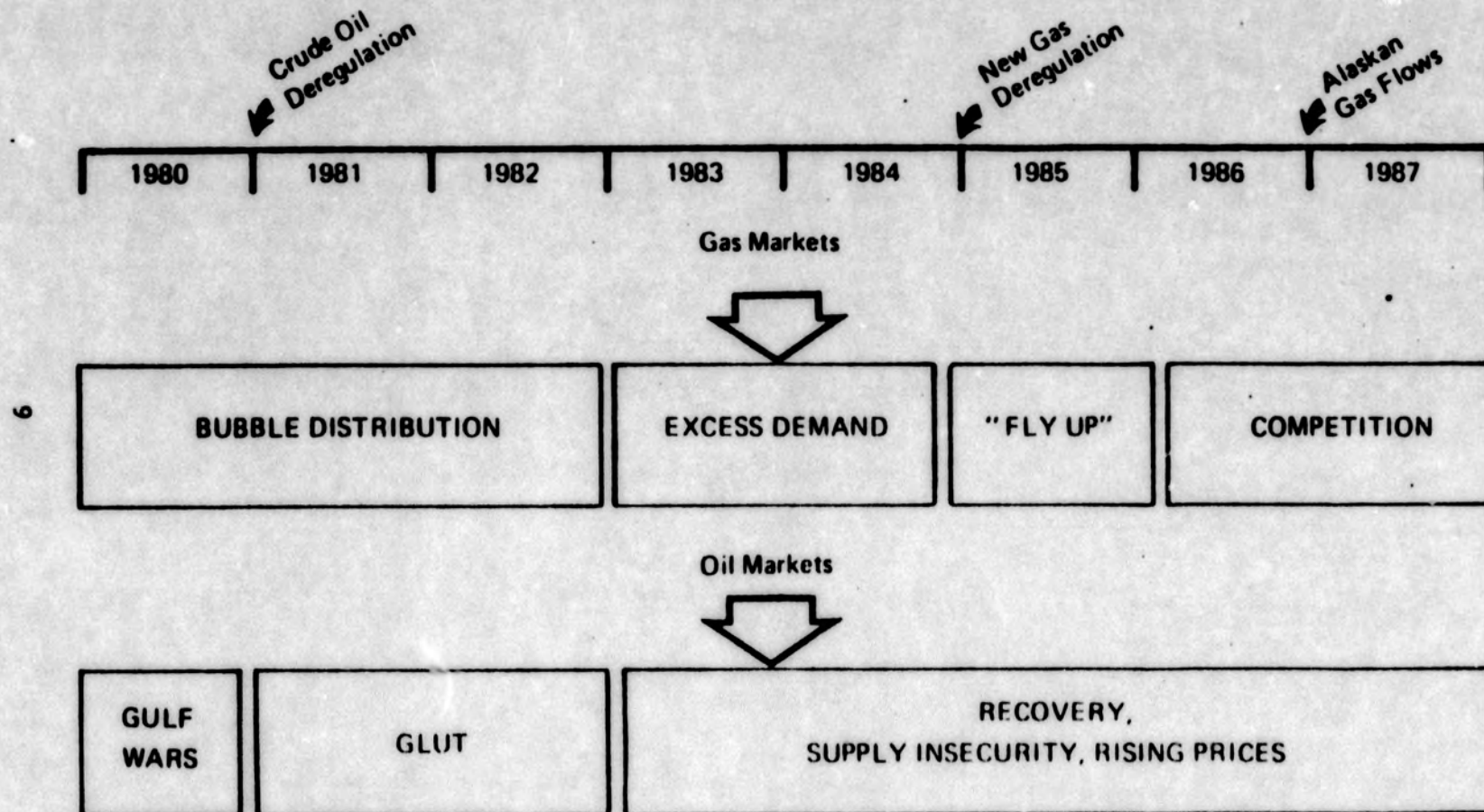
In projecting the evolution of gas/oil markets through the coming decade, the first new market environment which we envision is the return of excess gas demand. This is illustrated in Figure I-2. As the disparity between price-controlled natural gas and international oil prices continues, those customers with gas capability will increasingly prefer gas. In our view, this pattern was beginning to emerge during the 1979 oil price runup, but the creation of excess demand was blunted by the recession. But with a recovery from the recession, industrial demand should be restored. The economic driving force compelling dual-fuel demand towards gas will steadily mount.

Our detailed analysis of the demand potential suggests that gas demand would increase by 2 tcf between 1980 and 1985, if it were not constrained by supply. This is a demand level that the gas industry has not reached since 1973. Increasing conservation will limit the overall growth of residential and commercial demand. Growth in large boiler fuel and power generation uses will, we assume, continue to be restricted by federal regulation. Thus, the bulk of growth in demand would normally take place in high-valued industrial uses, primarily process gas. We estimate that about three-quarters of the overall demand increase will take place in the premium industrial fuel sector. The West South Central region, where most intrastate gas has been concentrated, has continually provided the largest increment of industrial demand growth and our projections assume that this will continue. One effect of the NGPA has been to control intrastate gas prices below competing fuels where intrastate markets were previously free to clear. Thus, the NGPA has created a financial incentive in both intrastate and interstate markets for industrial gas demand to grow.

The argument has frequently been advanced that many industrial gas users are reluctant to commit new or expanded installations to gas because of the potential unreliability of supply. The extent to which this threatened behavior is actually being practiced is debatable in our view. But,

FIGURE I-2

THE EVOLUTION OF GAS/OIL MARKETS DURING THE 1980's



the demand may not develop as we project unless the gas industry makes a credible statement about its supply potential during this period. Nevertheless, the disparity between regulated natural gas and alternate energy prices will provide an economic incentive for the high-valued industrial demand to utilize natural gas, whenever it is available.

Our projections for supply are not so optimistic. Lower 48 natural gas reserve additions have been less than production for twelve years. We do not expect reserve additions to rise to present production levels, despite accelerated drilling during the forecast period. For this reason we see a continuation of the steady decline of proved reserves.

The rate at which existing reserves are being depleted has been increasing in recent years. Part of this has been the result of intensive developmental drilling for higher producing rates. Some of it is also attributable to the concentration of discoveries in geological areas such as South Louisiana, where unconsolidated sands provide high permeability and extremely high well flow rates. Much of the newer reserves which will be added in other areas are not of such high permeability and therefore may not be subject to such rapid depletion. We anticipate that depletion rates will level out and, in fact, might well decline somewhat as the shift in exploration takes place. Thus, in our view, production from the Lower 48 States will continue to decline with declining reserves. The burden of maintaining supply will shift more and more to supplements such as imported gas, coal gasification or the Alaskan gas project under analysis here. Because of the lag times associated with many of these projects, their contribution will grow slowly, and in our view not fully offset the decline in the Lower 48 conventional production. Thus, we look for a slight decline in total supply between 1980 and 1990. The result of these demand and supply trends, we believe, will be a renewal of the excess demand which confronted the gas industry in the early 1970s.

It is important to recognize that this excess demand will tend to occur during the period when much of the industrial boiler and power generation load is fully convertible into alternate fuels and can be quite flexible in its shifting. Thus, we would expect to see increasing interruption of dual-fueled boiler and power generation customers to offset the limited gas supplies. The level of total interruption to be borne by these customers in 1985 could be as much as 3.7 tcf if all new loads actually grow as projected. Over 75 percent of the reductions in deliveries would be to large boiler fuel customers and power generating plants. Regionally, the reductions would be heavily concentrated in markets where boiler fuel and power generation are important.

As the NGPA is currently written, several of the gas categories will be deregulated in 1985. Congress clearly expected that gas markets would be in balance at that time and would permit an orderly transition to deregulation. However, since the price trajectories of regulated gas are so much lower than those of deregulated oil, one now could expect market

forces in 1985 to supply a significant gas price correction upon deregulation. This has been termed "flyup" in many discussions. One can picture a price correction for deregulated gas sufficient to bring the average value of all gas to market clearing levels. We call this level "allowable fly-up."

It is the existence of a quantity of gas remaining under regulation below market clearing levels--a so-called "roll-in" capacity--which permits flyup to occur. We estimate that in 1987 some 4.4 tcf of gas will remain under regulation. It is in our lower-bound oil price case that gas is priced approximately \$2.50 below clearing levels, creating some \$11 billion of roll-in capacity. Alaskan gas in 1987 requires \$3.7 billion of roll-in in this lower-bound case. In our least unlikely price scenario, the roll-in capacity rises to \$24 billion in that year and Alaska requires less than \$1 billion.

The relatively small annual volume of totally new reserves being committed after 1985 will be free to select price and contract terms without constraint. One could anticipate that undisciplined bidding for these comparatively small volumes of new supplies in a tight market could lead to quite high individual contract prices from the roll-in effect. There will also be a much larger volume of Section 102 and other gas (committed from 1977 to 1985) under contract which will be free to move to whatever internal limits the contracts themselves dictate. Where these contracts have provided for indefinite pricing provisions, such terms could well be triggered in 1985 and drag up a much larger volume of deregulated gas to higher levels as well. The actual way in which such flyup might occur is dependent both on the nature of the Section 102 gas contracts as well as on the market psychology of the time and its effect on the discipline gas buyers show to 1985 supply contracting.

Flyup is also an individual pipeline--rather than a nationwide--phenomenon. Some purchasing pipelines will clearly have more roll-in capacity; some will have less as contracting develops over the next years.

A further complication is the existence in many contracts of buyer escape clauses which enable the buyer to renegotiate his contracts downwards in the event of market pressures. One thus can envision a "flydown" effect as well, under certain circumstances.

The degree to which flyup will actually occur and absorb some roll-in capacity which could otherwise help to accommodate Alaskan gas is thus extremely difficult to estimate, particularly since much of the gas which will be subject to flyup is not yet under contract. We recognize that the gas industry could negotiate away much of its flexibility to absorb Alaskan gas, particularly in lower oil price cases. However, we sense a growing awareness of the problem among the pipelines, and see some evidence of attempts to address the issue through more careful supply planning. We thus believe it is manageable.

II. THE ROLE OF PRICE

Alaskan natural gas is expected to be delivered to the Lower 48 States in 1987 at a price which will range from \$7.70 to \$8.94 in constant 1980 dollars. This price range seems high when compared to the present prices of \$4.94 for Canadian or Mexican gas at the border, or the \$2.81 presently permitted for new (Section 102) gas under the NGPA, let alone the average price of \$2.02 for all gas industry supply. But in these days of volatile energy pricing, the critical price relationships are those which will prevail in 1987 when Alaskan gas comes on line, rather than those of today. We believe that the price relationships among Alaskan gas, other gas sources, and alternate fuels will have altered substantially by that time.

Perhaps the single most important element in competitive fuel price formation during the 1980s will be the outlook for international oil prices. Rising prices for OPEC oil supplies have two important effects on oil and gas competition. First, rising oil prices tend to stimulate the demand for gas at the expense of oil--particularly in the price-sensitive dual-fuel market. But since prices of most supplementary supplies, such as LNG or overland imports, will increasingly be tied to international oil price levels, rising oil prices make these sources relatively less attractive by comparison with Alaskan gas. Thus, a rising oil price environment makes Alaskan gas increasingly competitive, not only with oil, but with most other supplementary gas sources as well.

In 1973, at the time of the first oil price shock, interstate natural gas prices in the United States were price-regulated at levels which did not reflect competitive fuel values. Intrastate prices had been held below alternate fuel prices by price competition in a period of surplus intrastate reserves. Imported Canadian gas was priced on a netback basis from the price-regulated U.S. market. After the rapid increase in oil prices in 1973/1974, reserve shortages in the intrastate market caused intrastate prices to break free of interstate pricing and move to alternate fuel parity based on residual fuel oil. The Canadians abandoned the policy of netback pricing to the regulated U.S. market and began tying their prices unilaterally to changes in international oil price levels.

The Canadian precedent of tying export gas prices to international oil prices has spread and become the general practice nearly everywhere. The past two years have seen negotiations between the U.S. and Mexico, the U.S. and Canada, Japan and Abu Dhabi, the Soviet Union and Iran, and both the U.S. and France with Algeria--all over the relationships between oil and gas pricing in international trade. While no uniform formula for linking such prices has yet been developed, it seems nearly certain that future increases in world gas prices will be directly linked to changes in world oil prices.

Since the passage of the NGPA, nearly all U.S. gas supply--intrastate as well as interstate--has been placed under price regulation in which price escalation is independent of changes in international oil prices. We estimate that the price of only about nine percent of U.S. gas supply was affected by oil price changes in 1980. Somewhat less than seven percent of U.S. gas supply in 1980 was from supplementary sources, either oil-based SNG or imported gas, and less than three percent was deregulated conventional production.

But by 1985, with the deregulation of new gas and the growth of supplements, only 27 percent of gas supply will remain fully price-regulated. Supplements will account for 19 percent and deregulated gas for 54 percent of total supply. The role of price-regulated gas declines as it is depleted and as supplements constitute a growing share of the total.

In the 1980 environment, the rapidly rising price for oil made gas competitively attractive. But by 1990, a rapidly increasing price for oil will lead to a rapidly increasing price for gas as well, since much of the gas supply will be price-linked to oil. Gas supply sources which avoid this direct linkage--such as Alaskan gas with its 20-year average price range of \$4.22-\$5.63--will be relatively favored. In a 1990 environment of escalating world oil prices, Alaskan natural gas with its large capital costs, will increasingly look like a bargain as the facilities are depreciated and costs decline.

The Outlook for Oil and Gas Prices

The favorable market outlook for Alaskan natural gas is heavily influenced by the expected future course of competitive oil and gas prices. Because of the importance of these future price estimates to the conclusions of this study, we have laid our analysis out in some detail in this section.

In this report, we utilize two forecasts of oil prices. One of these--our least unlikely case--is based on the expectation that international oil price formation will operate very much during the 1980s as it has during the 1970s. The dominant feature of recent international oil price development has been a sporadic political or military crisis in the Middle East; this has generated panic buying in the marketplace and a rapid escalation in oil prices. These prices subsequently decline in real terms as the disruption passes and world economic activity reacts to the sharp dislocations in pricing. For our least unlikely case, we have arbitrarily assumed that a disruption will occur in 1984 and the pricing pattern both during and after the disruption will be similar to 1973/1974 and 1979/1980.

For purposes of this analysis, however, we have assumed that such a forecast, with its disruptive price pattern, would not present a credible test of the marketability of Alaskan gas. Therefore, we have utilized instead a "lower-bound" price case which represents the lowest level of prices that we think are plausible over the next decade.

It is this projection--one which assumes that political disruption will have no significant effect on oil prices throughout the decade--which we utilize in this report to test Alaskan gas marketability. The basic crude projection has been adjusted for transportation and other crude oil sources, and then converted into a price series for the refiners' acquisition cost of crude oil. This series has been used in turn to develop both distillate and residual fuel oil prices by region.

Our gas price projections are made individually for the many regulated pricing categories of gas under the NGPA, as well as for the various supplemental gas projects and import volumes. These prices are then modified for transmission costs and for distribution margins to arrive at regional estimates of retail gas prices by type of customer.

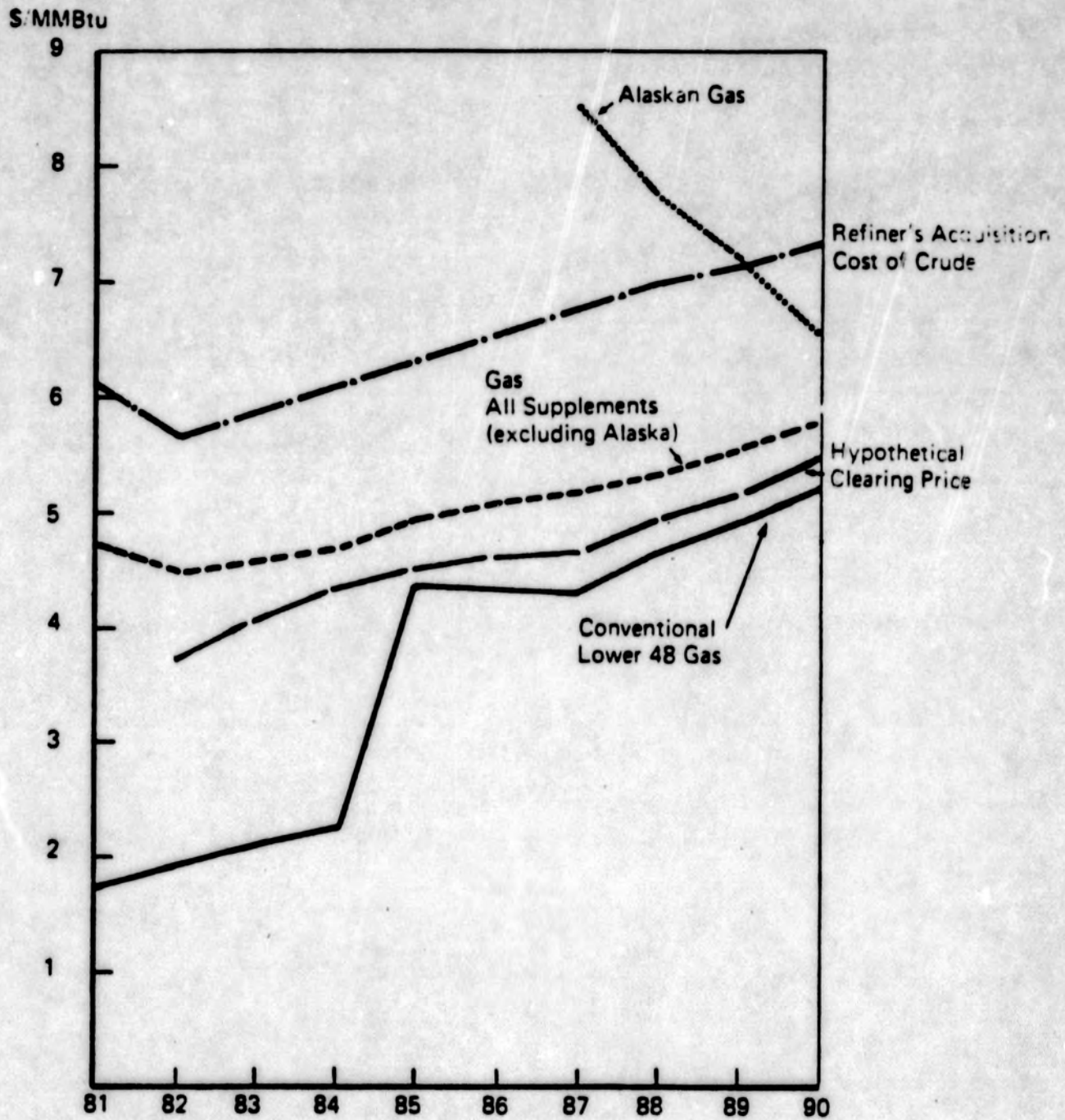
The period following new natural gas price deregulation in 1985 poses special analytical problems because of the uncertainties surrounding the price behavior of deregulated gas after that time. Since the middle 1970s, most contracts--interstate and intrastate--have been written with escalation clauses, in some cases indefinite escalation clauses, which continue to increase even though the current price itself may be limited by regulation. In 1985, when deregulation occurs, many of these contracts will move to the levels established by the contract terms. In those cases with indefinite price escalators which will be permitted to operate after 1985, the behavior of buyers and sellers in 1985 in setting new price levels will bring up the value of old contracts as well. This phenomenon of upward price pressure with deregulation in 1985 will finally be defined both by the nature of the contracts written between now and 1985, but also by the marketplace psychology in 1985, particularly as it influences the willingness of suppliers to bid competitively for short supplies. Our analysis suggests that there will be excess gas demand in 1985 from markets that would prefer cheaper gas to more expensive oil. We thus believe that some level of flyup is inevitable. Recent offers by gas pipeline companies as high as \$7-\$8/mcf for deep Tuscaloosa Trend gas in Louisiana indicate the potential for high prices in the early days of decontrol, while average gas costs remain low.

To illustrate the way in which flyup might operate, we have allowed the price increases for deregulated gas in 1985 to rise to a level high enough to bring average gas prices to estimated clearing levels. We call this "allowable flyup." Because of the disparity between gas and oil price levels at that time, the flyup price increases are comparatively large. Figure II-1 shows our projections of conventional Lower 48 prices (including "allowable flyup"), together with Alaskan gas, all other supplements, the hypothetical clearing price, and the refiners' acquisition cost for crude oil.

International Oil Markets and OPEC

From 1973 to 1981, prices of international oil to U.S. markets rose at an average rate of nearly 14 percent per year in real terms. This was not

FIGURE II-1
GAS WELLHEAD PRICES COMPARED WITH REFINER'S CRUDE ACQUISITION COST
 (1980 Dollars per million Btu)



Source: Jensen Associates, Inc.

a classical steady growth curve, however, since virtually all of the increase was confined to two comparatively short periods--October 1973 to February 1974 during the Arab oil embargo, and again from December 1978 to February 1980 precipitated by the Iranian revolution. There is thus compelling evidence that the dominant force in real price increases over the decade has been the panic buying which accompanied the crisis markets of 1973/1974 and 1978/1980 rather than any orderly price administration by OPEC. OPEC's principal role has been to resist the erosion of real oil prices during the periods between rises.

Both of the sharp price runups occurred when a sudden loss of production within OPEC occurred during periods of strong demand for OPEC oil. The embargo, through its politically mandated production cuts, took roughly 3 MMbpd of OPEC capacity out of service at a time when world economies were booming and demand was approaching physical capacity limits. The Iranian Revolution reduced Iranian production by nearly 5.5 MMbpd at a time when underlying demand was not so strong, but psychological fears of shortage caused unprecedented inventory accumulation worldwide.

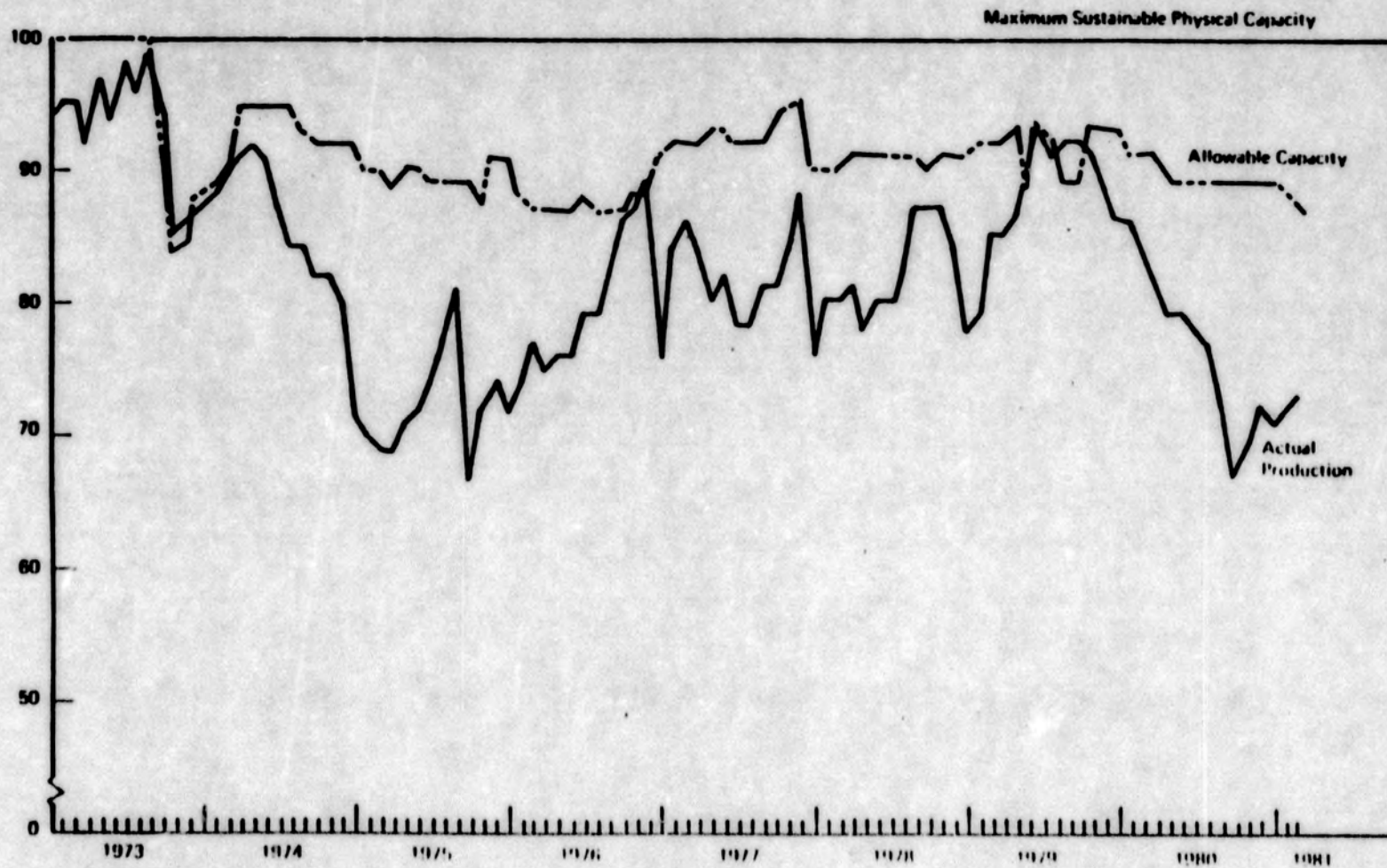
Except for these two periods of market-inspired price behavior, international oil pricing has largely been the result of OPEC price administration decisions within the context of OPEC political debate. Thus, for most of the past eight years, interpretation of the conflicting political pressures within OPEC has been a more important tool for projecting oil prices than the more classic economic analysis of supply and demand has been. This is not to say that supply and demand relationships are not important, but they have served to set the stage on which the price debate has taken place, rather than to establish prices directly.

Figure II-2 shows OPEC production and "allowable capacity" as a percent of maximum sustainable physical capacity within OPEC over the past eight years. In 1973 OPEC physical capacity stood at 32 MMbpd and most projections at the time expected it to rise to the lower to mid 40s by the end of the decade as steady demand for OPEC oil continued to mount. After the takeovers of control of their own oil which accompanied the 1973/1974 period, most OPEC members could not or would not increase capacity. However, since 1973, demand has been significantly less than had been anticipated earlier so the added capacity has been, for the most part, unnecessary. Physical capacity in OPEC peaked in 1976/1977 at 38 MMbpd and has since declined to 34 MMbpd, in part as a result of the loss--perhaps permanently--of a portion of Iranian capacity.

The concept of "allowables" was first developed by Kuwait, which has consistently argued that keeping oil in the ground is a safer way to protect surplus wealth than creating financial assets from higher production and revenue levels. Allowable limits have now been adopted by other surplus countries such as Saudi Arabia and Abu Dhabi. The argument of the surplus countries is that the world should not count on OPEC's delivering more than its allowable capacity even though production in excess of allowables may occasionally be utilized for special purposes. Saudi Arabia, for

FIGURE II-2

ACTUAL AND ALLOWABLE CRUDE OUTPUT AS % OF MAXIMUM SUSTAINABLE PHYSICAL CAPACITY



Source: Jensen Associates, Inc.

example, currently is producing 10.3 MMbpd against an allowable of 8.5 MMbpd as a part of its internal OPEC dispute over price reunification.

As is evident from Figure II-2, demand for OPEC oil was approaching physical limits in 1973 when the embargo sharply reduced OPEC's available production. While the price increases of October 1973 and January 1974 were OPEC-dictated, they were foreshadowed by a spot market which rose to even higher levels as a result of threatened shortages.

Figure II-3 shows the U.S. refiners' acquisition cost of imported crude oil in constant 1980 dollars compared to OPEC production as a percent of allowable capacity. In both the 1973/1974 and 1978/1979 price jumps, OPEC production exceeded allowable capacity. The only other time when that occurred was in the Winter of 1976/1977 when OPEC production reached an all time high of 34 MMbpd. An increase in the Saudi allowable capacity helped to avert a greater nominal price increase at that time.

Many observers--including ourselves--expected another possible upward price spike during the Winter of 1980/1981 with the loss of capacity from the Iraq-Iran war. Indeed, there was a flurry of rising spot activity in October and November which subsequently subsided. In retrospect, it appears that the market had weakened sufficiently so that the panic psychology which dominated 1979 markets was fully dissipated.

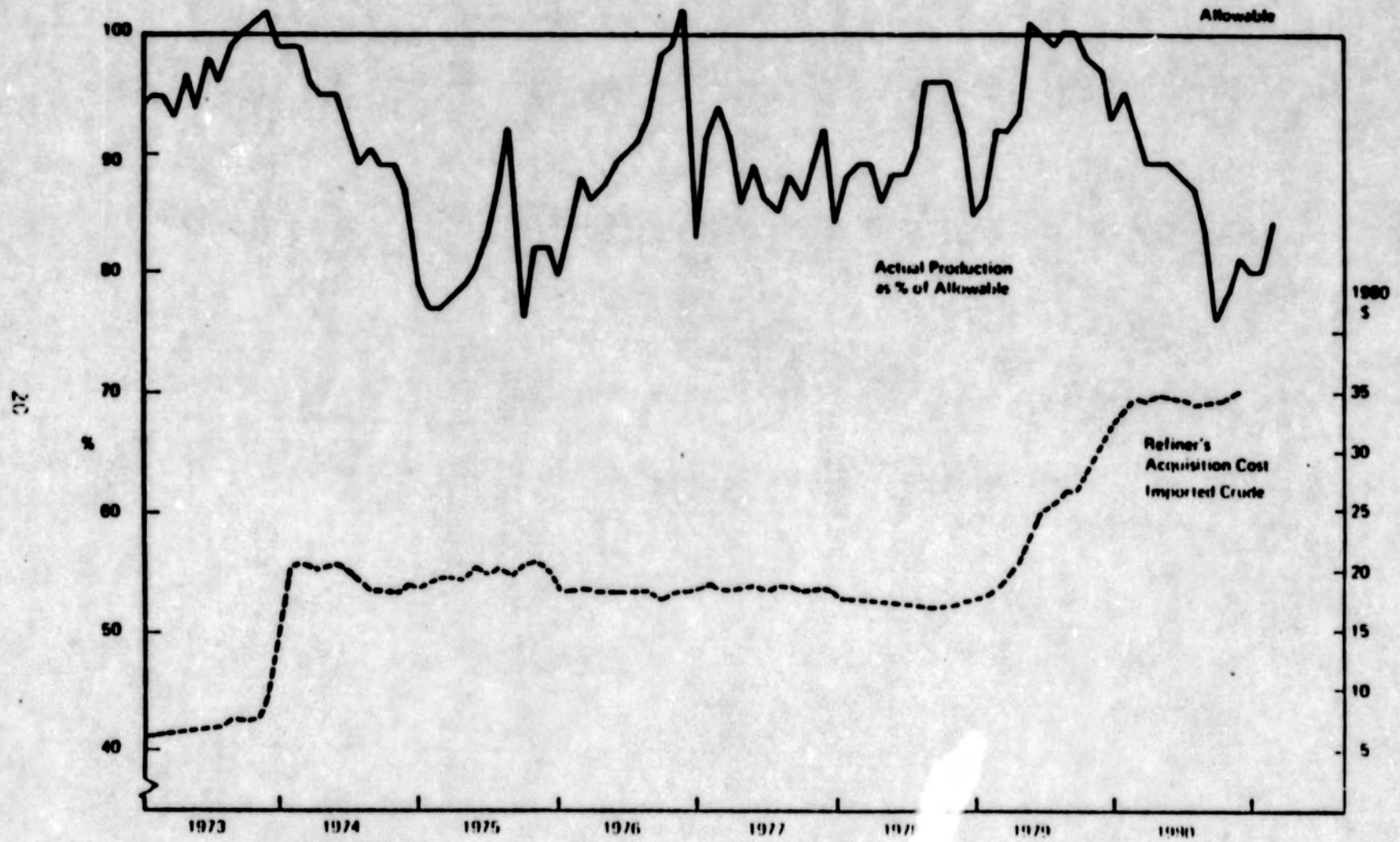
We are now--as of June 1981--in a much softer oil market than most forecasters anticipated. Free world demand for oil may fall to 46-47 MMbpd this year and net demand for OPEC oil could be as low as 23 MMbpd--the lowest level since 1970. This would place the demand on OPEC at about 74 percent of allowable capacity, a level even lower than in the weak market of 1975. The question is naturally being raised as to whether this low a demand represents a new long-term secular trend, and whether the assumption that OPEC can dictate price levels in all but tight and rising markets is still valid. Can OPEC, in fact, hold together and prevent further erosion of prices in a market such as this?

We at Jensen Associates believe that the underlying OPEC structure is not seriously threatened by present market conditions, despite an appearance of internal dissension within the organization. We view the present market downturn as more cyclical than long-term, although major long-term changes in demand are clearly taking place. The world oil surplus results largely from a reduction in energy demand--in part recession influenced--rather than an increase in alternate energy supply above expected levels. If anything, alternate energy supplies have consistently fallen below projected levels throughout the world.

There has been a tendency for OPEC oil to play a swing role in world energy demand. This tends to exaggerate the effect of short-term energy market changes on the demand for imported oil and suggests that a sharp 1981 downturn could be followed by a sharp rebound with improving world economic conditions. In a static world energy supply pattern, where OPEC

FIGURE II-3

CRUDE PRICES VS OPEC CAPACITY OPERATION



Source: Jensen Associates, Inc.

oil bore the entire swing in total demand, a downturn of one percent in world energy demand would manifest itself as a four percent downturn in OPEC oil demand. This would result from the fact that oil represents about half of energy supply, and OPEC oil is about half of total oil supply.

While OPEC oil does not fully occupy the swing role--downturns in the steel industry reduce coking coal demand and U.S. natural gas demand has been affected by a sluggish economy--we believe that most of the downturn is indeed concentrated on OPEC. World energy supply is also dynamic, rather than static, so that when previously planned increments of new alternate energy supply exceed the demand for them, they tend to back out imported oil selectively. Thus, we believe much of the present decline in OPEC demand is short-term, rather than long-term.

We expect to see a measure of economic recovery in the OECD by 1983 and anticipate a strengthening of demand on OPEC at that time. Thus, we look for a continuation of OPEC's ability to establish floors on world market prices during soft markets.

During the Spring and early Summer of 1981, the popular and business press has been full of reports of falling oil prices, and frequent suggestions that OPEC may in fact have lost its ability to prevent price erosion in soft markets. While it is clear that spot markets are falling, that some governments are cutting official selling prices, and that prices are declining in nominal as well as real terms, this evidence of price weakness in OPEC is somewhat misleading.

The chaotic markets of 1979 and 1980 led to substantial disorder in OPEC pricing patterns. During the more placid markets between 1974 and 1978, OPEC operated on a "marker crude" system in which the price of the principal Saudi crude--Arab Light--was priced by OPEC agreement and values of all other crudes were based on their quality or transportation differentials relative to Arab Light. The light African crudes from Algeria, Libya and Nigeria, for example, usually enjoyed about a \$1.50 per barrel premium over Arab Light based on both their higher quality and their relative nearness to market. Today those market-dictated differentials are perhaps no higher than \$2.00 per barrel.

During the turbulent markets of 1979, some OPEC governments were able to command prices which had little market logic since buyers were desperate to have secure supply regardless of price. Some of the African crudes have been officially priced at \$41 per barrel--a full \$9 per barrel over the official government selling price of Arab Light at \$32 and therefore much higher than the normal market differential of \$1.50-\$2.00. The highly publicized oil price cutting has been concentrated in the abnormally high differentials being asked by the price hawks, rather than in the underlying price structure of the Arab Light marker.

Before the Iranian Revolution, OPEC, with strong Saudi support, established a long-range strategy committee to consider a number of long-term

problems facing OPEC. One major focus of the study was a desirable future course for world oil prices. The committee's recommendation was for a gradual but steady increase in real crude prices to replace the stop-start pattern of crude price increases which characterized the 1970s. The committee called for a formula to adjust the price to cover inflation, to adjust for changes in the value of the dollar, and to add a real price increment based on the growth of GNP within the industrialized countries. It has been quite clear that Saudi Arabia has been a major backer of this proposal within OPEC. However, the orderly pricing formula presumes a unified and orderly set of differentials about the marker crude. The 1979 market conditions effectively destroyed the unified OPEC price structure which could serve as a base for the application of the long-range pricing formula.

The Saudi official price for Arab Light has been \$32. Most other OPEC members have adopted a "deemed marker crude" which most commonly is based on the assumption that the marker sells for \$36. "Special market premiums" over and above normal differentials have been adopted by some governments.

The present Saudi policy of producing at 10.3 MMbpd rather than at their 8.5 MMbpd allowable in the face of world oil surpluses seems designed to force market realignment of the hawks' differentials about some orderly marker crude structure.

Until recently we--like many other oil market observers--believed that the Saudis were sufficiently committed to the OPEC long-range planning formula that they were prepared to make price concessions on their \$32 in order to reunify the system. Indeed, the Saudis themselves had sold "war relief oil"--a special offering designed to assist those who had lost supply because of the Iraq-Iran war--at a price of \$36. This led many observers to conclude that this was the logical compromise price for a unified marker system.

More recently, however, it appears that the Saudis have become concerned at the extent of the 1981 downturn in OPEC oil demand, questioning whether prices have gotten too high. They now appear to have shifted policies to force compromise nearer their present \$32 official price, despite the ill will which that effort appears to be earning them in some OPEC circles. Some of the widely publicized price cuts by the OPEC members are consistent with the \$36 or a \$34 marker. The \$32 marker is as yet not accepted as a compromise standard.

The Crude Price Projections

Our lower-bound crude oil price projection assumes that the unified price will be based on a real \$32 marker (as of June 1981) which will hold through the end of 1982. With a pickup in world oil demand in 1983, the real price will again start to rise with the long-range planning formula at a rate of about three percent per year. The actual unification may not require that other OPEC members be forced to recognize and accept that \$32

price, since it would be possible for them to save face by freezing at some higher level until the inflation-dictated increase in the nominal marker price rose to an appropriate level.

Our least unlikely case assumes surpluses persist through 1982, as well, and that the formula is applied in 1983. However, it also assumes that some disruptive market event will occur before 1987--we have arbitrarily placed it in 1984--with price behavior during and after the event similar to the 1973/1974 and 1979/1980 disruptions. The least unlikely case, with its disruption, results in an overall real price increase of eight percent per year to 1990. While this is significantly higher than many current oil price projections, it is considerably lower than the 14 percent per year actual real price increase from 1973 to 1981. The increase in the lower-bound case is 2.5 percent per year over the same period. These projections are shown in Figure II-4.

Oil Prices for the U.S.A.

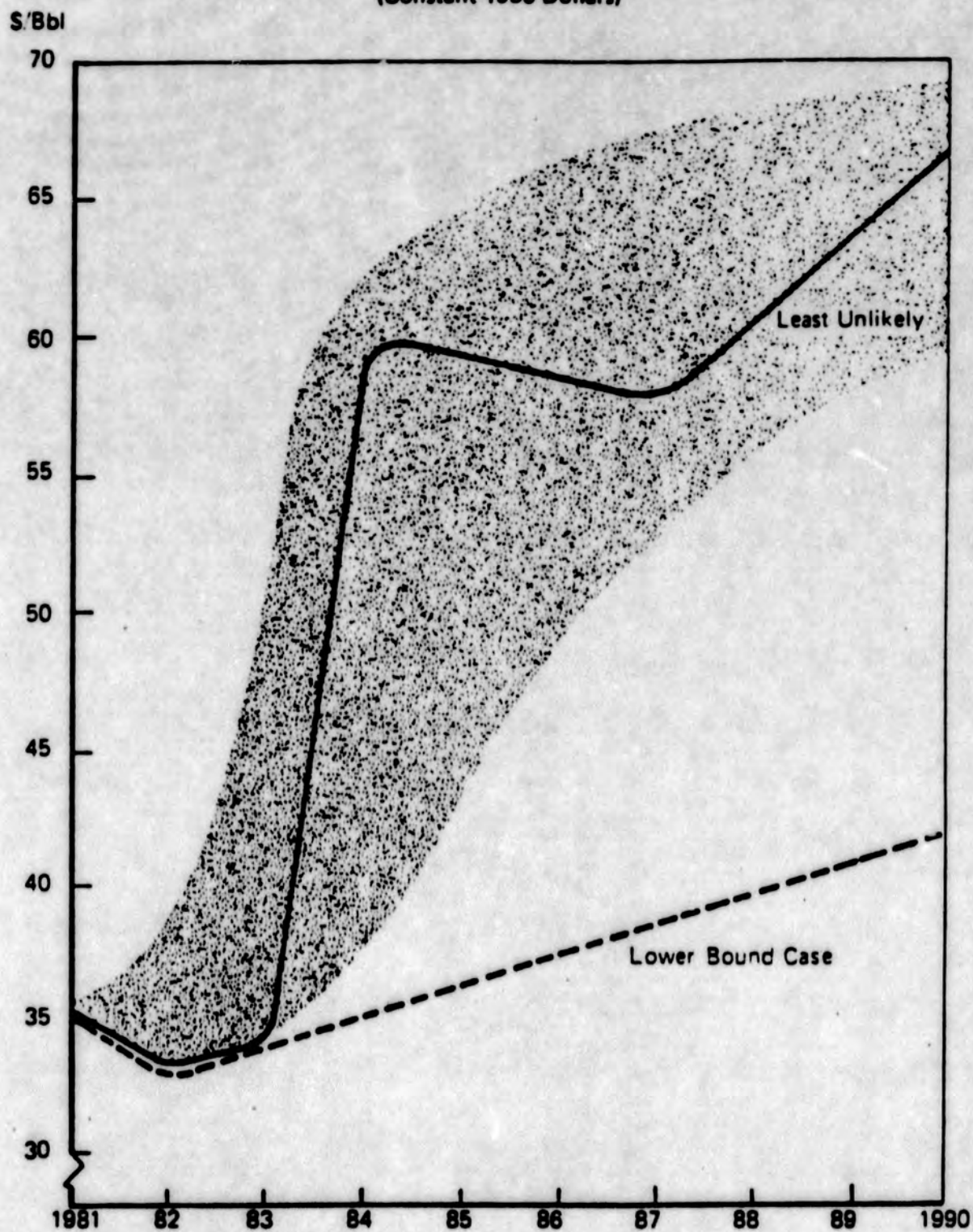
We have forecasted a basic crude oil price in the Arabian Gulf, f.o.b. the export terminal. Such crude has to be transported to the U.S.; it will form only part of a selection of crudes that American refiners import; and the oil with which Alaskan gas competes in regional final markets will be refined products, mainly No. 2 oil and No. 6 oil.

Even while a surplus of capacity overhangs the world tanker market, there continue to be quite sharp fluctuations in freight rates--partly because the surplus is not uniform for all sizes of vessels, and partly because unpredictable demands for tonnage (e.g. recently for Very Large Crude Carriers and Ultra Large Crude Carriers for use as floating storage) often occur. More generally, the shift of a growing proportion of crude oil exports from the integrated trading channels of the international major oil companies into non-integrated trading by OPEC national companies with smaller scale private buyers or governmental buyers downstream has reduced logistic efficiency in the whole international employment of tankers. Slow steaming to reduce fuel costs, again, involves more tankers for any given ton mileage of crude oil movement.

Those factors have raised oil transport costs during the last two years. High prices for oil fuels will continue to tilt the economics of tanker operation. Logistic inefficiencies arising from less integration in world oil trading may also persist. On the other hand, the deepening and widening of the Suez Canal that has now been completed, and the possibility of further increases in its capacity to handle large tankers by about 1985, point to some reduction in the average distances that oil will have to move by sea to markets. And recent forecasts by tanker experts that freight rates may resume an upward trend (as distinct from short-term fluctuations) by about 1983-1985 have generally assumed rather higher growth rates in the world economy for this decade than most analysts now seem inclined to count upon.

FIGURE II-4

PROJECTIONS OF THE DELIVERED PRICE OF OPEC'S MARKER CRUDE
(Constant 1980 Dollars)



Source: Jensen Associates, Inc.

Detailed predictions of tanker employment and freight rates thus remain as complex as ever. But for the projection of landed prices for crude, it has become less important. Freight costs now represent such a small proportion of c.i.f. prices that one's assumptions about the changes in them make little difference to the projections we have made of crude prices f.o.b. Arbitrarily, we are assuming that average tanker freight costs from the Arabian Gulf to the Texas Gulf remain constant in real terms until 1985, and then rise five percent in real terms annually to 1990. But freight is now so small in comparison with the f.o.b. price that our resultant projections of c.i.f. crude prices (Figure II-4) differ hardly at all in slope from the f.o.b. price trajectories we have already set out. (An alternative assumption raising this real freight cost increase to 10 percent annually, or starting it earlier, would make a difference of cents rather than dollars per barrel.)

Product Prices

Natural gas competes with distillate fuel oil in residential, some commercial, and high-value industrial markets. It is most likely to compete with residual fuel oil in industrial boiler fuel and power generation markets. Since the higher-valued, distillate-competitive markets tend to be protected from erosion by both price and priority curtailment status, it is residual fuel which incremental gas supplies most tend to displace.

We have estimated future refinery margins both for distillate and the several sulfur grades of residual fuel oil in making our regional analyses of interfuel competition. Typically, high-sulfur residual fuel oil sells below the cost of crude oil in the United States, while distillate fuel oil carries significant refining margin premiums. These product differentials tend to be volatile, depending on market conditions, and variations can be especially severe in the case of high-sulfur fuel oil in sloppy markets. Nonetheless, total margins between distillate and high-sulfur residual fuel oil in the U.S. tended to average out in the \$3.00-4.00/bbl range during much of 1976 and 1977. From late 1978 through 1979, margins blew apart (rising to above \$10.88/bbl at one point) as the worldwide problem of adapting to market pressures for lighter, sweeter product mixes came into conflict with the trend toward greater availability of heavier, higher-sulfur crudes. With the worldwide recession and product surpluses more widespread, margins have again collapsed closer to traditional levels.

In our estimates, we expect the tendency will be for wider, rather than the traditionally narrower, product price spreads as the growing need for deeper cracking, coking and hydrogen processing by refiners greatly increases refining complexity and costs. Our margin projections reflect these judgments and are incorporated in our regional interfuel competition analysis.

III. FORECAST OF LOWER 48 STATES GAS SUPPLY

Summary Forecast

An important part of analyzing the marketability of Alaskan North Slope natural gas is the overall gas supply forecast for the Lower 48 States (L48) against which gas demands can be compared. The Jensen Associates' forecast of gas availability to the L48 during the period 1980-1990 is provided as Table III-1. It includes both conventional L48 natural gas production and supplemental sources.

Overall, we expect supply to the L48 to decline from 20.5 tcf in 1980 to about 18.5 tcf in 1990, or by 10 percent during the decade. The net loss of 2.0 tcf results from an expected 5.1 tcf drop in conventional production being partially offset by a 3.1 tcf increase in annual supplemental supplies available by 1990. The supplemental supplies forecast includes unconventional production from low-permeability reservoirs, North Slope gas, Canadian and Mexican pipeline imports, LNG imports and high-Btu synthetic gas manufactured from light liquid hydrocarbons and coal.

Lower 48 States Production

Natural gas reserves and production statistics of the American Gas Association (AGA) show that conventional L48 production rates for natural gas peaked at 22.5 tcf in 1973, then fell annually through 1978 to a level of 19.1 tcf. In 1979, this trend was reversed as production rose to 19.7 tcf, despite a continuing decline in proved reserves which started in 1969. The year 1979 also showed some improvement in L48 reserve additions--reaching nearly 14 tcf. This was considerably better than the 9.8 tcf annual average additions for the 1970s. Table III-2 summarizes natural gas reserves and production figures for the period 1966-1979. Figure III-1 highlights the erosion of the proved reserves base which has occurred as production annually exceeded reserve additions between 1968 and 1979.

Although the AGA no longer develops or publishes gas reserves and production estimates, preliminary figures from the U.S. Department of Energy indicate that L48 production will be down by 0.3 tcf in 1980 from 1979, or at a level of 19.4 tcf on the AGA scale.

Despite this recent slowing in the decline of L48 gas production, we believe that the pace will quicken again during the 1980s. We expect average annual natural gas reserve additions for the L48 will remain substantially below production levels and that, at some point, production rates as a percent of proved reserves will peak, causing production to fall more rapidly thereafter. In recent years, production has been held above 19 tcf per year by steady increases in the rate-of-take from remaining reserves. This has occurred as a result of increased emphasis on in-fill and other relatively low-risk developmental drilling activity. This type of drilling

TABLE III-1

LOWER 48 STATES TOTAL GAS SUPPLY FORECAST
1980 - 1990
(Trillion cubic feet)

<u>Source</u>	<u>1980^a</u>	<u>1985</u>	<u>1990</u>
Conventional Production	19.4	16.1	14.3
Unconventional Production	0	0.1	0.3
Alaskan Gas	0	0	0.7
Canadian Imports	0.8	1.6	1.4
Mexican Imports	0.1	0.4	0.7
LNG Imports	0.1	0.5	0.7
SNG - Oil Feed	0.1	0.1-0.4	0.1-0.4
- Coal Feed ^b	<u>0</u>	<u>nil</u>	<u>0.2</u>
Total Supply	20.5	18.8-19.1	18.4-18.7

^a Preliminary.

^b Excludes low and medium Btu gas.

Source: Jensen Associates, Inc.

TABLE III-2

NATURAL GAS PROVED RESERVES AND PRODUCTION

LOWER 48 STATES

1966-1979

(Trillion cubic feet)

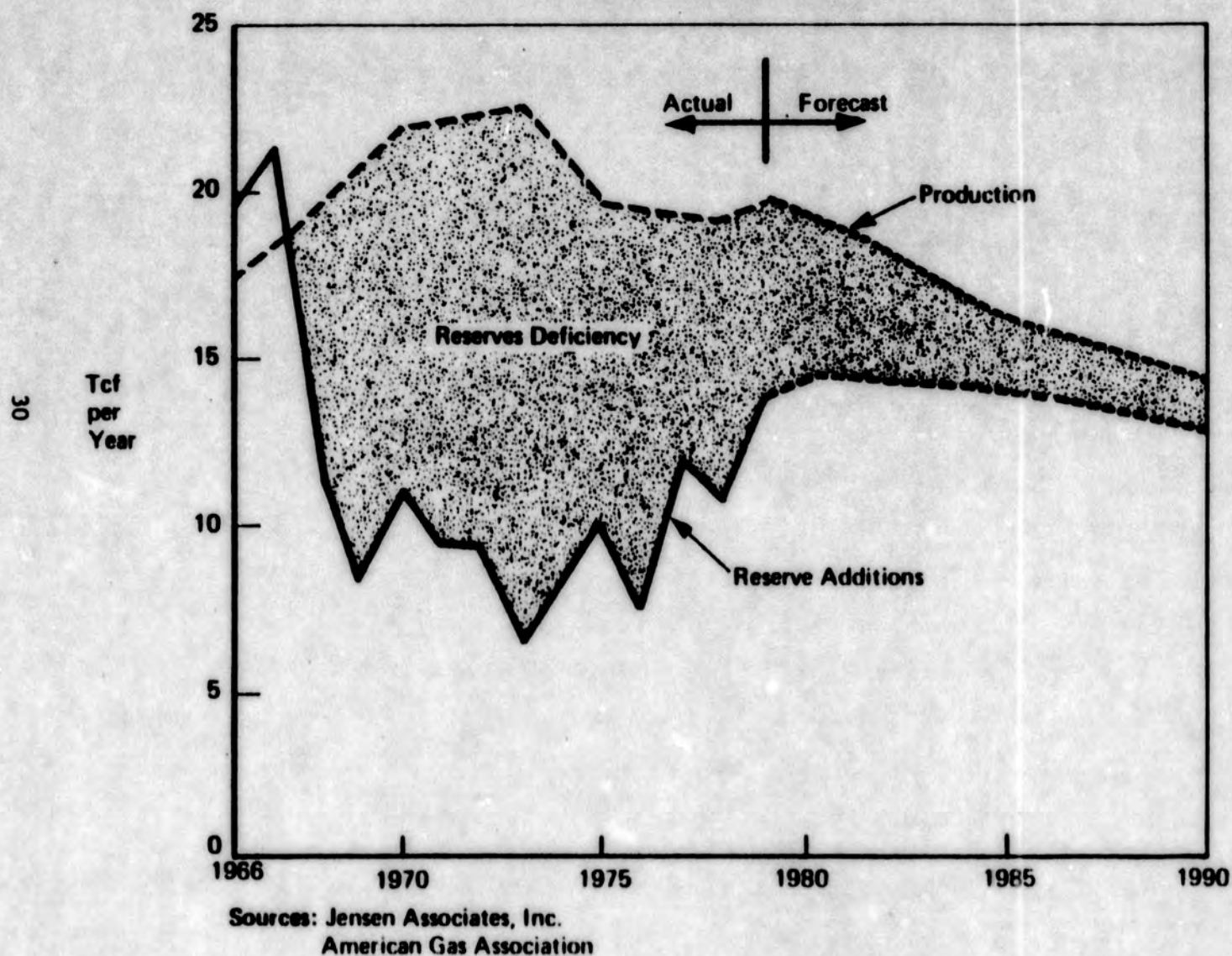
<u>Year</u>	<u>Year-end Proved Reserves</u>	<u>Annual Production</u>	<u>Annual Additions to Proved Reserves</u>	<u>Annual Decline in Proved Reserves*</u>
1966	286.39	17.48	19.25	(1.91)
1967	289.27	18.36	21.09	(2.88)
1968	282.10	19.33	12.04	7.17
1969	269.91	20.64	8.34	12.19
1970	259.62	21.82	11.12	10.29
1971	247.44	21.92	9.44	12.18
1972	234.63	22.37	9.40	12.81
1973	218.31	22.47	6.51	16.32
1974	205.27	21.17	8.31	13.04
1975	196.15	19.56	10.14	9.12
1976	184.10	19.32	7.45	12.05
1977	177.05	19.26	11.76	7.05
1978	168.69	19.10	10.59	8.36
1979	162.98	19.69	13.73	5.71

* Includes changes in volume of gas in underground storage.

Source: Jensen Associates, Inc.

American Gas Association, American Petroleum Institute, "Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the U.S. and Canada"

FIGURE III-1
NATURAL GAS PRODUCTION AND RESERVE ADDITIONS
LOWER 48 STATES 1966-1990
(trillion cubic feet per year)



was stimulated by the large increases in real prices for interstate gas made available in 1976 by FPC Opinions 770 and 770-A.

The relationship between natural gas reserves and production rates, expressed as a reserves-to-production (R/P) ratio for the years 1966-1979, is shown in Table III-3. After appearing to flatten out at a value of about 10 in the mid 1970s, the R/P ratio continued to fall through 1979. In 1977 when the R/P ratio first dropped below 10, there was a significant increase in the developmental gas well share of total gas wells completed and this increased emphasis on developmental wells has been maintained through 1980 as shown in Table III-4. The higher gas prices which we believe caused this jump in developmental drilling activity can be seen in Table III-5. In 1976, FPC Opinions 770 and 770-A increased the National Rate by 91 cents per mcf for wells drilled after January 1, 1975. The effects these higher prices for gas from new wells had on average wellhead prices are shown in Table III-6, in both current dollars and constant 1980 dollars.

Our gas production forecast is based on analyses of historic trends in both proved reserve additions and production from proved reserves. For reserve additions, this means that we evaluate drilling activity in the major gas-producing areas of the country. We analyze those market forces which have affected the level of gas and oil well drilling and then forecast a level of activity for the 1980-1990 period. Reserve additions, however, do not automatically flow from additional drilling. Some measure of the success of drilling must be applied. Past finding rates (the amount of gas found per foot of well drilled) are studied and projected. When finding rates for a given period are combined with forecast drilling, the product is an estimate of future reserve additions.

American Petroleum Institute (API) drilling data show that gas well drilling activity has been increasing each year since 1971. The most dramatic increase occurred in 1977 when footage exceeded the previous year by over 12 million feet. Table III-7 shows both gas and oil well drilling statistics for the 1966-1980 period. Examination of the figures in Table III-7 shows that although healthy gas well footage increases have continued through the period, there has been a definite decrease in the rate of growth in absolute and percentage terms since 1977. In 1978 and 1979, this slackening may have been caused by drilling activity having caught up with the available rigs, manpower, and other supporting systems necessary for a major drilling increase. However, by 1980, it appears that lead times for a buildup have been met as evidenced by the recordbreaking increases in gas plus oil well footages.

From Table III-7 and Figure III-2, it can be seen that in 1980 oil well drilling had taken preference over gas. Oil well footage climbed 30 million feet in 1980 versus seven million feet for gas. In all but two other years during the 1970s, gas well footage increases have exceeded oil well footage increases. The attractiveness of rising oil prices and the promise of crude oil price deregulation in 1981 had cut deeply into the gas

TABLE III-3

NATURAL GAS RESERVES/PRODUCTION RATIOS*
LOWER 48 STATES
1966-1979

<u>Year</u>	<u>R/P</u>
1966	16.3
1967	15.6
1968	15.0
1969	13.7
1970	12.4
1971	11.8
1972	11.1
1973	10.4
1974	10.3
1975	10.5
1976	10.2
1977	9.6
1978	9.3
1979	8.6

* = Previous Year Reserves
Current Year Production

Source: Jensen Associates, Inc.
American Gas Association/American Petroleum Institute, "Reserves
of Crude Oil, Natural Gas Liquids and Natural Gas in the U.S. and
Canada"

TABLE III-4

GAS WELL COMPLETIONS BY TYPES
LOWER 48 STATES
1967-1980

<u>Year</u>	<u>Gas Wells Completed</u>	<u>Percent of Gas Completions</u>		
		<u>Developmental</u>	<u>Exploratory</u>	<u>Wildcat</u>
1967	3,655	85.5	14.5	5.1
1968	3,449	85.9	14.1	3.7
1969	4,072	84.9	15.1	5.7
1970	3,835	87.5	12.5	4.8
1971	3,829	88.6	11.4	5.3
1972	4,926	87.8	12.2	5.5
1973	6,382	85.9	14.1	6.5
1974	7,236	83.5	16.5	6.2
1975	7,576	84.6	15.4	5.9
1976	9,084	84.6	15.4	6.0
1977	11,374	87.0	13.0	4.6
1978	13,060	87.7	12.3	4.1
1979	14,677	87.9	12.1	4.6
1980	15,727	87.5	12.5	4.4

Source: Jensen Associates, Inc.
American Petroleum Institute, "Quarterly Review of Drilling
Statistics"

TABLE III-5

CEILING PRICES FOR "NEW" VINTAGE NATURAL GAS^a
(Current dollars)

<u>Year</u>		<u>Ceiling Price</u>
1970	Hugoton-Anadarko Area (FPC Opinion 568)	19.0¢-20.5¢/mcf
1971	Southern Louisiana Area (FPC Opinion 598)	26¢/mcf
1973	Permian Basin Area (FPC Opinion 662)	35¢/mcf
1974	National Rate (FPC Opinion 699)	42¢/mcf (+ 1¢/annum)
1974	National Rate (FPC Opinion 699-H)	50¢/mcf (+ 1¢/annum)
1976	National Rate (FPC Opinions 770, 770-A)	\$1.42/mcf (+ 1¢/quarter)
1978 (December)	Natural Gas Policy Act	\$1.97/mcf ^b Section 103 gas \$2.08/mcf ^b Section 102 gas
1981 (March)	Natural Gas Policy Act	\$2.41/mcf ^b Section 103 gas \$2.73/mcf ^b Section 102 gas

^a The definition of "new" is not uniform, and at times depends upon contract date, well commencement date, and other criteria.

^b Includes escalation adjustments to the indicated month.

Source: Jensen Associates, Inc.

TABLE III-6

AVERAGE WELLHEAD PRICE FOR NATURAL GAS
UNITED STATES
1966-1980
(Dollars/mcf)

<u>Year</u>	<u>Current Dollars</u>	<u>1980 Dollars</u>
1966	0.157	0.36
1967	0.160	0.36
1968	0.164	0.35
1969	0.167	0.34
1970	0.171	0.33
1971	0.182	0.34
1972	0.186	0.33
1973	0.216	0.36
1974	0.304	0.46
1975	0.445	0.62
1976	0.580	0.77
1977	0.790	0.99
1978	0.905	1.06
1979	1.144	1.25
1980	1.47 estimated	1.47

Source: Jensen Associates, Inc.
Department of Energy, "Monthly Energy Review"

TABLE III-7

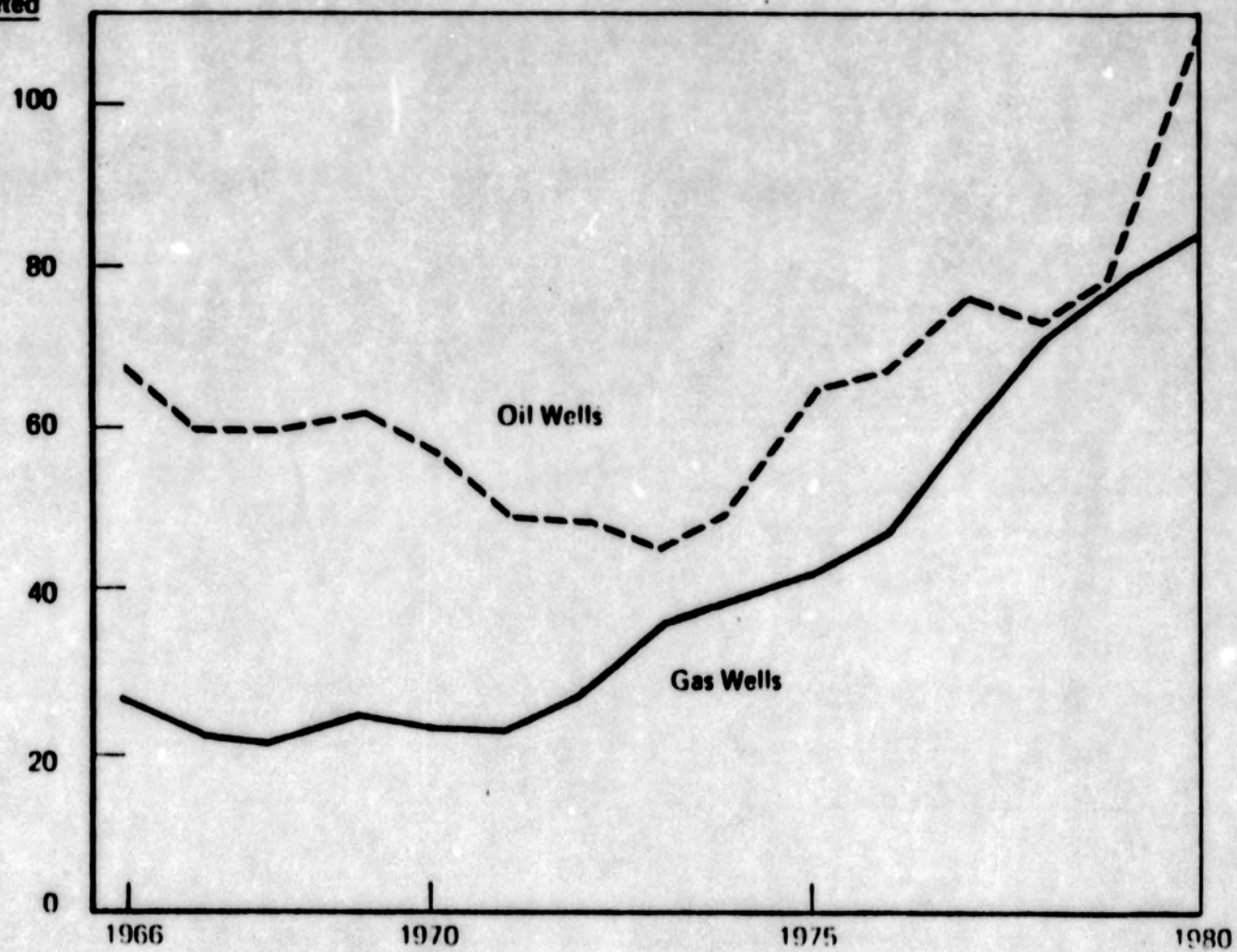
GAS AND OIL WELL COMPLETION FOOTAGE
LOWER 48 STATES
1966-1980
(Million feet)

Year	Gas Well Completions			Oil Well Completions			Gas Share of Completion Footage
	Footage	Annual Increase	% Increase	Footage	Annual Increase	% Increase	
1966	25.91	--	--	67.07	--	--	27.9%
1967	21.53	(4.38)	(16.90%)	58.24	(9.10)	(13.51%)	27.0%
1968	20.67	(0.86)	(3.99%)	58.67	0.43	0.73%	26.1%
1969	24.06	3.39	16.40%	61.13	2.46	4.19%	28.2%
1970	22.85	(1.21)	(5.03%)	56.39	(4.74)	7.75%	28.8%
1971	22.61	(0.24)	(1.05%)	48.27	(8.12)	(14.40%)	31.9%
1972	26.75	4.14	18.31%	48.41	0.14	--	35.6%
1973	35.59	8.84	33.05%	44.43	(3.98)	(8.22%)	44.5%
1974	38.98	3.39	9.53%	50.01	5.58	12.56%	43.8%
1975	41.90	2.92	7.49%	64.09	14.08	28.15%	39.5%
1976	47.49	5.59	13.34%	66.20	2.11	3.29%	41.8%
1977	59.51	12.02	25.31%	74.85	8.65	13.07%	44.3%
1978	70.18	10.67	17.93%	72.06	(2.79)	(3.73%)	49.3%
1979	77.72	7.54	10.74%	78.15	6.09	8.45%	49.9%
1980	85.03	7.31	8.41%	108.37	30.22	38.67%	44.0%

Source: Jensen Associates, Inc.
American Petroleum Institute, "Quarterly Review of Drilling Statistics"

FIGURE III-2
GAS AND OIL WELL COMPLETION FOOTAGE
LOWER 48 STATES 1966-1980
(million feet)

Million
Feet
Completed



Source: Jensen Associates, Inc.
American Gas Association

share of drilling activity in 1980. API reports that through March 1981, oil well completions are running 35 percent ahead of the same period in 1980, while gas well completions are five percent behind last year's rate, indicating even further drilling preferences for oil over gas may be occurring.

Because of the significantly higher real prices available for many types of regulated gas and the promise of deregulation in 1985, we believe gas well drilling will continue to increase, but at a slower rate, into the late 1980s before leveling off at a plateau nearly 45 percent above the 1979 pace. Thus, we expect the NGPA price incentives to cause a continuation of the gas well drilling surge which began in 1976 as a result of higher real prices made available for interstate gas by the National Rates of the Federal Power Commission. Increases in oil well drilling should support associated/dissolved gas production approximating 10 percent of the gas volume available from gas wells.

We expect a continuation of the long declines in gas finding rates from gas and oil well drilling. Figure III-3 presents actual finding rates for non-associated and associated/dissolved gas for 1966 through 1979. Units are in mcf of annual gas reserve additions per foot drilled as completed gas wells. Separate rates are shown for cases with annual reserve revisions included and excluded. Both cases show a rapid fall in finding rates for non-associated gas through the early 1970s, moderating to a more gradual decline in recent years. The cause of this trend change is the higher real prices available for gas, which tend to push more previously marginal wells into the commercial category.

Statistics for 1980 show that an increasing share of gas well drilling has gone to exploratory wells where risks are higher, but chances of major discoveries are improved. This, plus any increase in the availability of Federal lands for exploration, could also be helpful in improving finding rates. Finding rates for associated/dissolved gas from oil wells are also expected to continue their more gradual decline through 1990 and beyond.

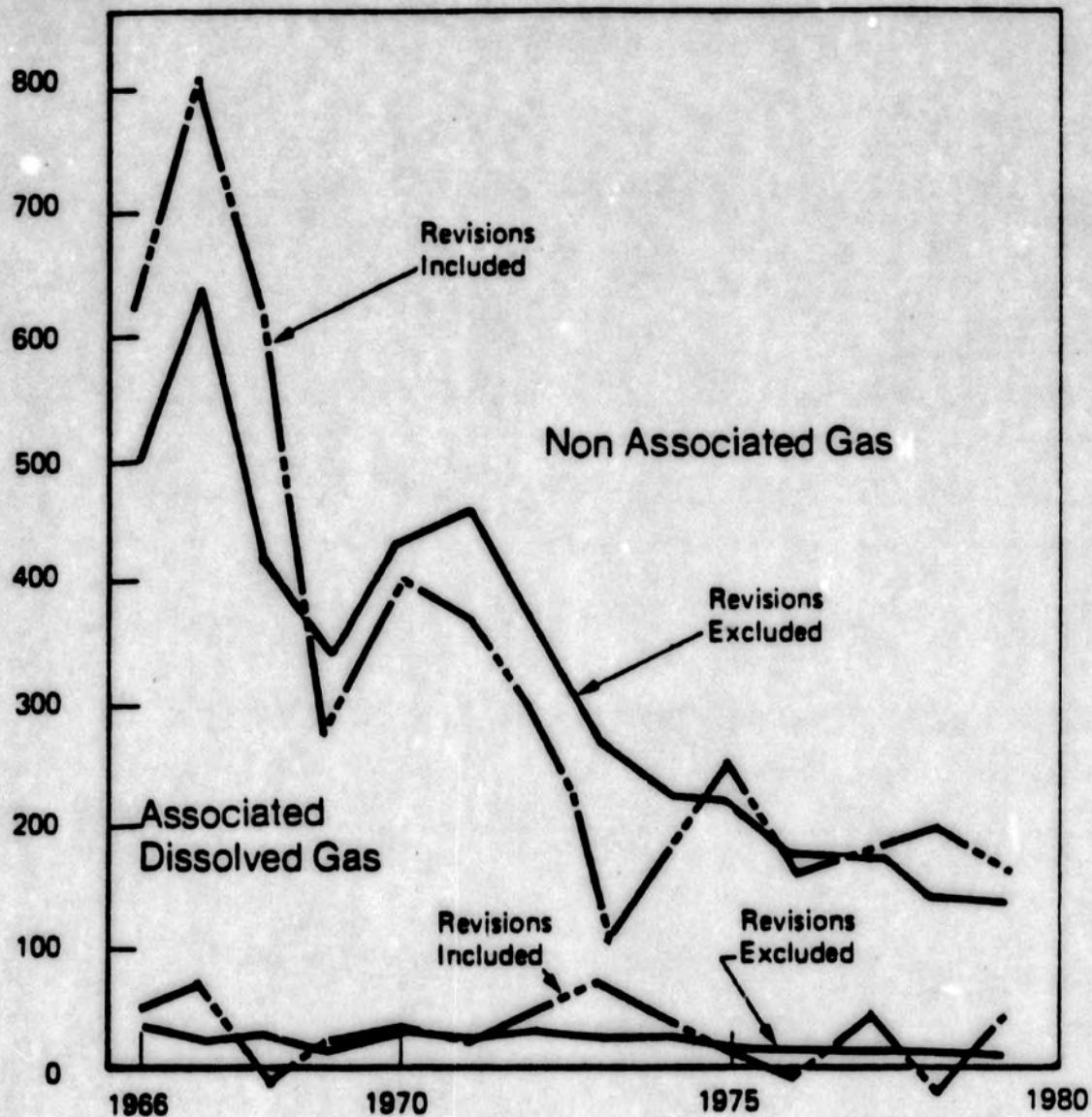
We forecast non-associated gas finding rates to decline from 150 mcf per foot drilled to 103 mcf between 1980 and 1990. Gas well drilling rates are expected to increase from about 85 million feet in 1980 to 112 million by the late 1980s. The product of these two factors results in non-associated gas reserve additions of 12.8 tcf in 1980, dropping to 11.5 tcf by 1990. Separately, associated/dissolved reserve additions increase from 1.1 to 1.2 tcf during the 1980s. Thus, total gas additions are forecast at 13.9 tcf in 1980, and gradually fall to 12.7 tcf by 1990. These reserve addition levels are well below the production rates of 19 to 20 tcf per year experienced in the late 1970s. A continuing decline in proved reserves will result if production rates remain higher than future reserve additions.

The present administration is more likely to push for accelerated Federal leasing programs--particularly offshore--than was the Carter

FIGURE III-3
NATURAL GAS FINDING RATES
LOWER 48 STATES

Mcf per
 Foot
 Completed

1966-1979
 (mcf/foot)



Source: Jensen Associates, Inc.
 American Gas Association/American Petroleum Institute,
 "Reserve of Crude Oil, Natural Gas Liquids and Natural
 Gas in the U.S. and Canada"
 American Petroleum Institute, "Quarterly Review of Drilling Statistics"

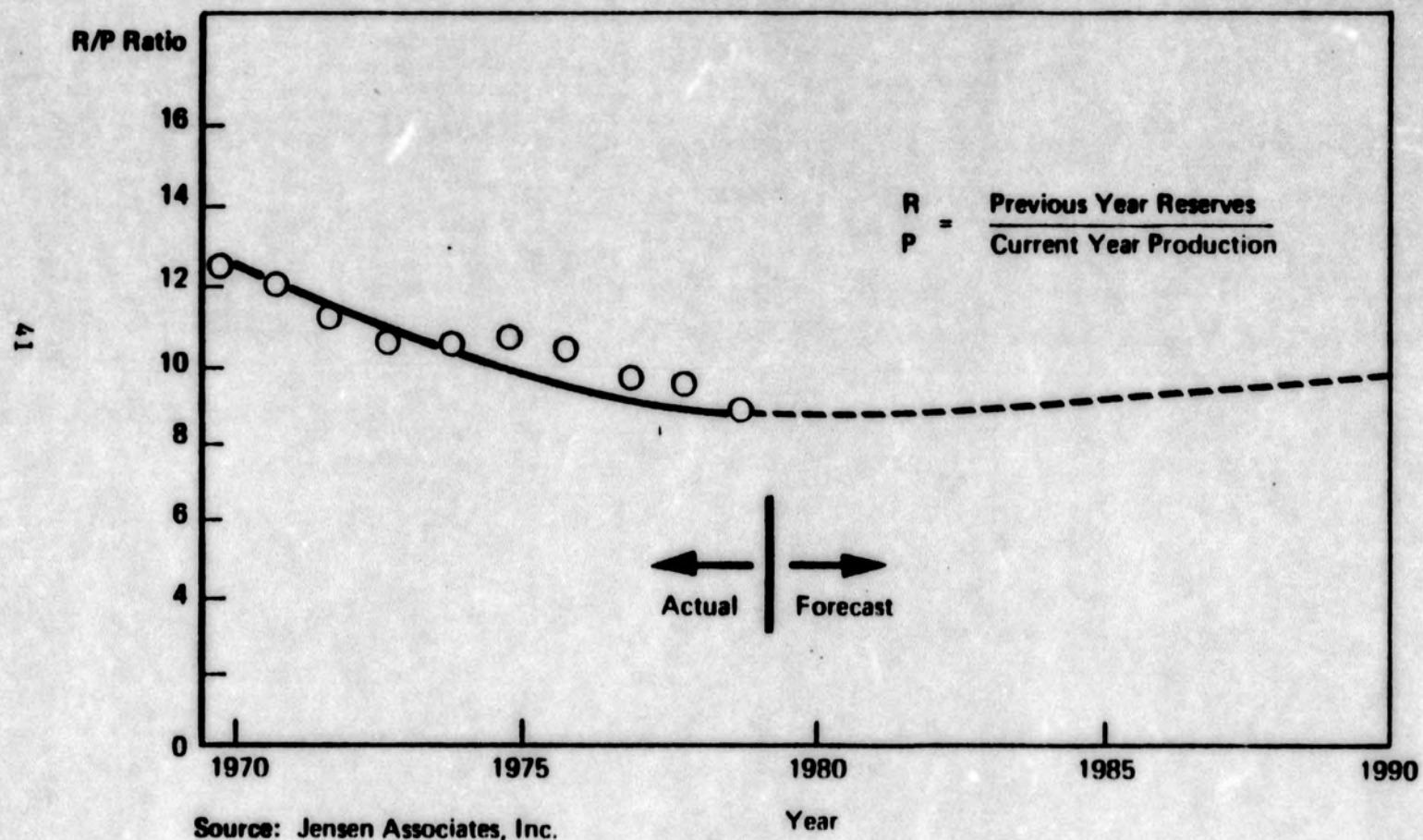
Administration. Much has been said about the positive effects on discovery rates, particularly for oil, which such an accelerated program could provide. It is important to recognize, however, that the potential positive effect on gas during the 1980s is likely to be much less than for oil. The relatively higher costs of gas pipeline transportation with its necessary emphasis on scale economies means that gas finds in new offshore areas will tend to be commercial only if they are large and/or relatively near existing transport systems. The limited near-term commercial prospects of the small East Coast Baltimore Canyon gas discoveries, or the unlikely early commercial utilization of gas discoveries in offshore Alaskan waters, illustrate the likely slower commercialization of offshore gas than oil. We do not see accelerated leasing as having a major impact on conventional gas supply during this decade.

As stated earlier, gas production would have fallen more rapidly in recent years as proved reserves plunged, if the percentage of reserves taken as production each year had not been increasing. Increasing production rates relative to proved reserves generates a falling R/P ratio. Table III-3 provides an historic series of R/P ratios for L48 natural gas, using the annual year-end AGA reserves estimate and the following year's annual production rate. With the exception of a small increase in 1975, the R/P ratio has declined steadily throughout the 1970s. We believe this decline in the R/P ratio is near an end, as explained below.

So long as annual reserve additions are less than annual production rates, the average age of L48 gas reservoirs is increasing. Since pressure decline reservoirs are typically capable of delivering a smaller percentage of remaining reserves each year, older reservoirs tend to increase the average R/P ratio. At some point in time, a minimum R/P ratio (maximum average depletion rate) for all reservoirs must be reached. Its level and timing will depend upon economic and technological factors that control field development. Increasing reservoir age will eventually cause the R/P ratio to rise again as production rates decline relative to remaining reserves. Changes in these observed relationships between reserves and production are expected to be very gradual due to the inertia of more than 160,000 producing gas wells in the Lower 48 States.

We believe that the combined effects of increasing average age of reservoirs, slower growth in gas well drilling, probable decreasing emphasis on developmental drilling, increasing interest in tight gas sands, and extended gas well life provided by higher real prices will prevent the L48 R/P ratio from falling below 8.4 in the near term and cause the R/P ratio to increase very slowly in later years, as shown in Figure III-4. If the R/P ratio should move to lower levels as a result of near-term increases in production above our forecasts, the L48 will experience a more rapid, proved-reserves drawdown (for a given amount of reserve additions) and, consequently, in later years, production rates will drop to levels lower than we have forecast.

FIGURE III-4
NATURAL GAS RESERVES/PRODUCTION RATIO
LOWER 48 STATES



Examples which support our assumption that the past trend of falling R/P ratios will be reversed are found in two of the more prolific new gas plays in the Lower 48--the deep Tuscaloosa Trend and the Rocky Mountain Overthrust Belt. Both are expected to have R/P ratios considerably higher than the national average figure. In both areas, field development and/or production facility investment are too costly to justify close spacing of wells and high rates-of-take. Low permeabilities are an additional factor in the Overthrust Belt area. This means that more reserves will have to be proved up to obtain a given production rate than is currently necessary in the balance of the Lower 48.

Using the methodology and projections described above, we have forecast gas supply from Lower 48 conventional production to decline from the 1979 level of 19.7 tcf to 16.1 tcf in 1985 and 14.3 tcf in 1990. These figures are nearly identical to the National Research Council's Enhanced Supply scenario published in 1979¹ (after adjusting for inclusion of Alaskan gas by NRC) and are nearly six percent lower than the Department of Energy National Energy Plan II forecast which is endorsed by the American Gas Association. Our forecasts are 1.0 tcf higher than the Middle Oil Price Scenario (Medium Geology) supply case published in the Department of Energy 1980 Annual Report to Congress by the Energy Information Administration.

Canadian Gas Imports

Canada's present gas situation may be characterized as one of oversupply relative to that country's internal needs. From 1972-1979, Canada increased its proved natural gas reserves base 46 percent from 61 tcf to 88 tcf. During this same period, internal Canadian gas sales grew less rapidly (34 percent) than the reserves base and a restrictive export policy was designed to reduce the long-term flow of gas to the U.S. This period of "reserves building" resulted in a recognized surplus of available gas by the late 1970s.

In December 1979, Canada's National Energy Board, which approves all gas exports, reversed then existing policies designed to reduce gas exports and allowed the first significant increases in Canada's export levels since the early 1970s. Much of the newly-approved export volumes will move through the "pre-build" western and eastern legs of the Alaskan natural gas pipeline system, commencing in late 1981 and late 1982, respectively. The volumes of Canadian gas available to the L48 are projected to be 1.6 tcf by 1985 and then to decline slightly to 1.4 tcf by 1990 as development of markets in eastern Canada occurs, siphoning off the exportable gas surplus.

¹ National Research Council, U.S. Energy Supply Prospects to 2010, 1979.