STATEMENT OF JAMES T. JENSEN

IN THE MATTER OF

YUKON PACIFIC CORPORATION
ERA DOCKET NO. 87-68-LNG

on behalf of

ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION CO.

JENSEN ASSOCIATES, INC.
Boston, Massachusetts

PREPARED STATEMENT OF JAMES T. JENSEN

ON BEHALF OF

ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY

IN THE MATTER OF

YUKON PACIFIC CORPORATION

ERA DOCKET NO. 87-68-LNG

Public Conference
January 24, 1989
Anchorage, Alaska

Prepared by
James T. Jensen, President
Jensen Associates, Inc.
129 South Street
Boston, MA 02111

Introduction

James T. Jensen, President of Jensen Associates, Inc., an independent energy economics consulting firm, has been asked by Alaskan Northwest Transportation Company to provide an independent judgment on two issues pertinent to the application by Yukon Pacific Corporation (Yukon Pacific) to export Alaskan gas to Japan. These issues are the following:

(1) Are there sufficient proved and economically transportable gas reserves on the North Slope to warrant construction of two major large-diameter pipeline systems in the same time frame?

(2) Will the currently proved Prudhoe Bay gas reserves be needed more by the United States or the Pacific Rim countries in the years ahead?

This statement addresses those issues.

Overview Implications of the Yukon Pacific Application for ANGTS

The decision which the Economic Regulatory Administration (ERA) is being called upon to make in this application is without precedent in the U.S. or international gas experience. The decision will inevitably have a major influence on the way in which the pipeline infrastructure ultimately develops for transporting natural gas from Alaska's North Slope to market. The major risk inherent in this decision is that the size and quality of the proved reserves on the North Slope are not adequate to support the construction of two independent transportation infrastructures for Pacific and U.S. gas markets. In such a case the award of this application to Yukon Pacific runs the risk of prejudicing the ultimate construction of a transportation link between North Slope gas and Lower 48 states markets. Further development of the North Slope gas resources could then become dependent on energy market developments in the Asian countries rather than on those in the United States. The public interest implications of ERA's decision in this matter are thus long-term and strategic in nature.

The natural gas industry in the United States is the oldest and most mature gas industry in the world. Most of the pipeline infrastructure on which the transportation of gas from the

producing regions to markets depends was in place by the early 1950's. With the movement to market-responsive pricing and open transportation, gas in the Lower 48 states is approaching commodity status.

From a U.S. gas industry perspective, therefore, it may be difficult at first to recognize that the policy decision we are discussing in this proceeding, in fact, bears far greater resemblance to the decisions which are being addressed today in countries such as Norway or Nigeria, than it does to any gas policy issue that the United States has ever had to face. For Norway and Nigeria, as with many countries throughout the world, proved reserves of natural gas far exceed any foreseeable local market, and the prospect of developing "mega-projects" to export the gas to other markets is under active discussion. Similarly for Prudhoe Bay gas, local markets on the North Slope are virtually non-existent and it requires a "mega-project" to "export" the gas to any reasonably sized consuming region. This includes not only the international markets of the Pacific Rim countries, but also "export" to the Lower 48 states.

There are two very significant differences between the decision we are discussing today and that which other potential gas exporters face. First, the remoteness of Prudhoe Bay from markets and the very high costs of Arctic construction virtually guarantee that any transportation infrastructure will be one of the most expensive private sector energy projects in the world. It thus forces the project to take maximum advantage of economies of scale and minimize the costs of field development, gathering and treatment if it is to have any hope of economic viability. And second, because the infrastructure of the TAGS and ANGTS systems is so different, there is little prospect that the two systems will provide substantial mutual economic support for one another. Norway's North Sea pipeline grid system to the Continent, in contrast, does not foreclose the possibility of future shipments to the U.K. nor does it make it difficult to "piggyback" a U.S.-oriented LNG project onto the grid as Norway has just announced. And Nigeria's proposed LNG liquefaction facility at Bonny similarly does not preclude shipments to either Europe or the U.S.

The requirement that the infrastructure be largely duplicated for both TAGS and ANGTS together with other key issues discussed below, however, may effectively force the ERA to make an either/or choice between the two projects.

Specific Issues in Delivering Alaskan Gas Economically to the Lower 48 States

A critical element of the ANGTS project and presumably also of the TAGS system is the issue of minimizing the costs of transporting Alaska gas from the wellhead to market. In general, there are three areas in which project planners can address this issue. They are by:

- taking advantage of economies of scale in constructing pipeline facilities to minimize costs;
- minimizing the costs of finding, developing and gathering gas; and
- reducing the costs of financing to the lowest extent possible.

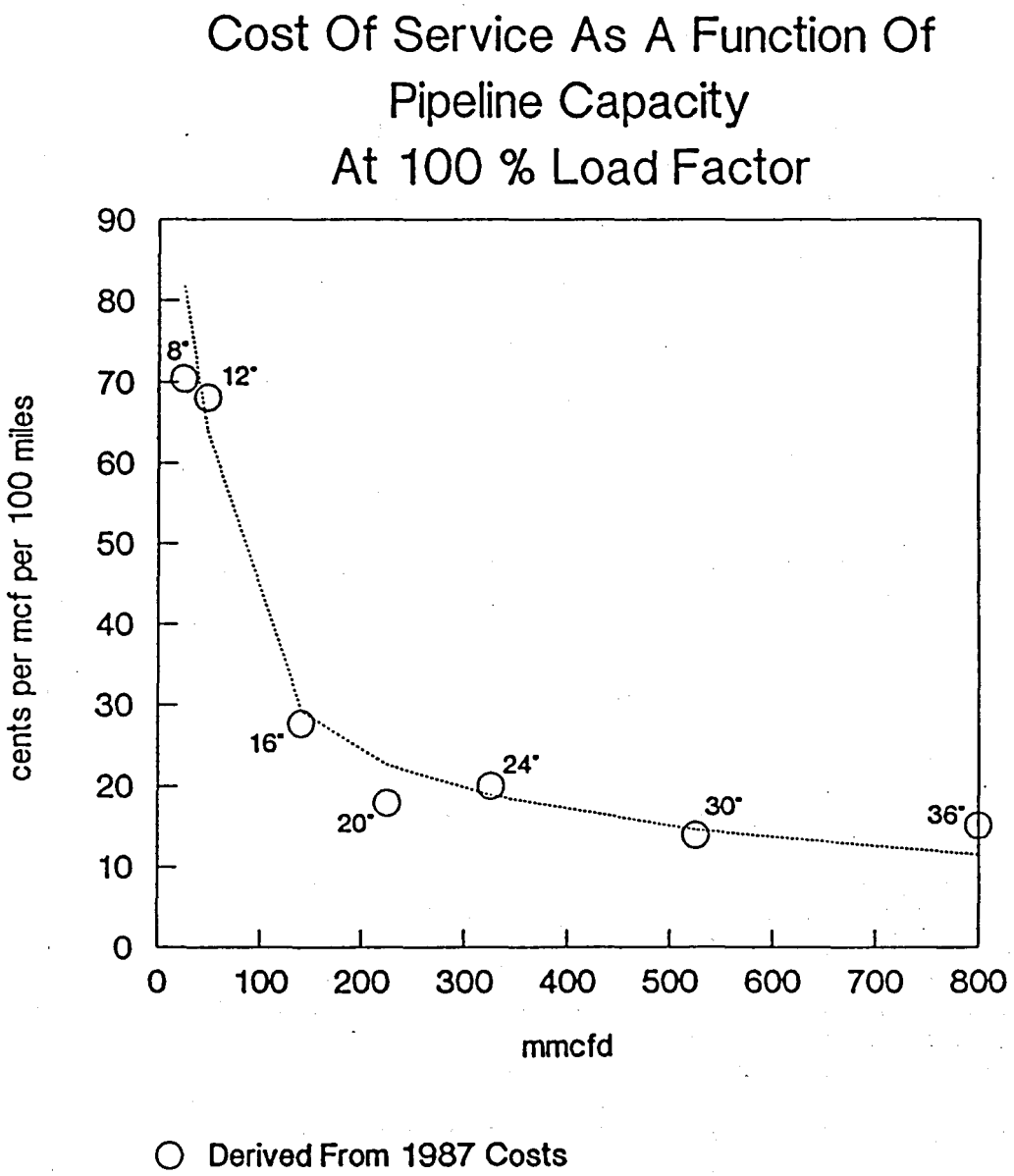
In pipelining, economies of scale are a significant factor since substantial savings can be achieved through the use of larger diameter pipe if flows warrant. In effect, capacity increases much more rapidly with increasing diameters than does pipeline investment.

Figure 1 shows the effect of pipeline diameter and thus throughput on the costs of moving gas per 100 miles of pipeline. It is based on onshore pipeline investment costs for 1987 as reported in the Oil and Gas Journal. Alaska pipeline investment costs for Arctic terrain will be much higher. (In order to minimize pipelining costs within Alaska, the ANGTS has resorted to an even larger pipe size with commensurately higher throughputs than is shown in Figure 1.) As a result of its use of a 36 inch pipe diameter pipeline, the TAGS LNG project, at its ultimate design level would be more than twice the size of the largest existing LNG project anywhere in the world.

Issue One: Are there sufficient proved and economically transportable gas reserves for two major pipeline systems in the same time frame?

Because of the size of the ANGTS and TAGS projects, they each require the commitment of very large quantities of proved reserves

FIGURE 1


Cost Of Service As A Function Of
Pipeline Capacity
At 100 % Load Factor
cents per mcf per 100 miles
90
80
70
60
50
40
30
20
10
0
0
100
200
300
400
500
600
700
800
mmcfd
8"
12"
16"
20"
24"
30"
36"
Derived From 1987 Costs

if they are to be financeable. The ANGTS project has always assumed that it will require the entire 26 TCF of Prudhoe Bay Sadlerochit reserves if it is to be viable. And even the 16 TCF of reserves which the TAGS project requires represents more than 50% of all reserves remaining on existing contracts from the six countries exporting to Japan, Korea, and Taiwan combined.

This raises the major question as to whether enough relatively low cost, quality proved reserves exist on the North Slope to finance both projects. The final financing will be subjected to very close scrutiny by the lending agencies to assure them that the projects will be economic. This will undoubtedly require both an economic feasibility study with guarantees of wellhead prices in the form of contracts or other binding assurances of gas cost, as well as concrete evidence that there are sufficient proved reserves to guarantee that the pipeline will remain full. For such a feasibility study, vague promises of the potential of discovered but undeveloped reserves or resources will be inadequate. The lending institutions will want to be assured of the costs of the gas as well as its physical availability.

The mining industry uses the term "highgrading" to describe the process of taking out the richest and thus most profitable portion of the ore body first. Basing the development of any gas transportation infrastructure on those reserves which are the least expensive to develop and gather is a form of "highgrading" and will benefit the project which is first able to utilize Prudhoe Bay gas.

It is here that the great concern about the quality of the reserves which will be available <u>after</u> Prudhoe Bay becomes important. Prudhoe Bay is the fifth largest accumulation of natural gas ever discovered in the world outside the Soviet Union and the Middle East. Its reserves are proved in every sense of the word, and much of the costly field facilities which would be required to deliver it to the pipeline inlet are already in place. Gathering lines, some gas compression, and even a portion of the gas processing facilities required to make the gas of pipelineable quality have already been built. The economics of the further gas reserves which would be needed to support a second pipeline are largely unknown. Even the highly regarded Point Thompson gas condensate discovery near Flaxman Island has not been developed sufficiently to warrant inclusion in the proved reserves category of either the U.S. Energy Information Administration or the Alaska Oil and Gas Conservation Commission. Thus the ultimate cost of its gas is largely unknown at this point and could be high.

The experience of several overseas projects and their concern with the development costs associated with particular reserves is instructive. The first example is in Pakistan. The Sui gas field in that country would rank as the world's sixth largest outside the Soviet Union and the Middle East. It has been the basis for the development of the gas industry in that country. The World Bank uses Pakistan to illustrate one of its contentions regarding gas development economics in an Energy Department Paper. In the paper it says of Pakistan:

> In Pakistan, the large volumes of gas production and economies of scale in production and transmission lead to low supply costs. The marginal cost for different gas fields are presented in Table (sic) 4. Pakistan has a relatively mature gas industry, and the production to reserve ratio has been increasing. It is now producing from its lower cost fields. As demand increases and supply from these fields fall, the more expensive fields will come under operation.[1]

The accompanying Figure 4 is included here as Figure 2.

It is the risk of forcing ANGTS to rely on fields which may be much more expensive to develop than Prudhoe Bay which is the major concern here. Other examples of this sort of concern are readily available.

Both Norway and Nigeria are actively exploring new projects to bring LNG to European and/or U. S. markets. In both cases recent press releases have indicated that gas cost minimization has been aggressively pursued to try to make the project feasible.

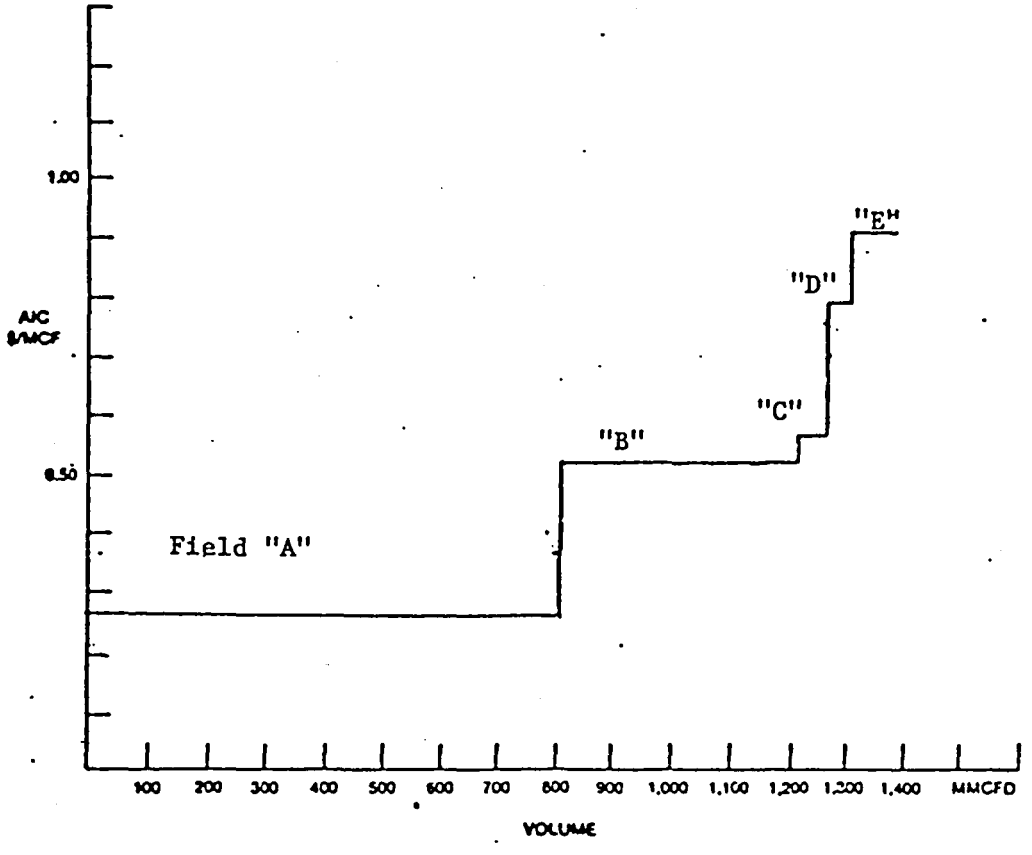
Norway was widely reported to be trying to develop its northernmost fields in the Troms area of the North Cape for an LNG project. The recent announcement of a contract for U.S. markets indicates instead that they have tried to cut costs by "piggybacking" on the existing Statpipe system out of the Statfjord field farther south. In announcing the contract, R. Gerald Bennett of Enron was reported as saying,

---

[1] "Marginal Cost of Natural Gas in Developing Countries: Concepts and Applications" Energy Department Paper No. 10, August 1983, The World Bank Energy Department, Washington, DC, pages 15-16.

FIGURE 2

THE AVERAGE COST OF GAS BY FIELD IN PAKISTAN



Source: "Marginal Cost of Natural Gas in Developing Countries: Concepts and Applications" Energy Department Paper No. 10, August 1983, The World Bank Energy Department, Washington, D.C., page 16.

About the economics of the Norwegian LNG, Bennett said the Norwegians are looking at a site next to an existing LNG facility at Karsto, north of Bergen for the liquefaction plant. The supply will come from uncommitted gas reserves in several large North Sea fields and transmission capacity is available in existing pipelines. The Norwegians have already invested a significant amount to develop the gas fields and believe they can add the liquefaction facilities on an incremental cost basis.[2]

Nigeria, too, in its efforts to minimize costs, has been highly selective of the gas reserves which would be committed to its proposed LNG scheme. An article in the Petroleum Economist describes the process as follows:

These fields [earlier named as Soku, Bomu, Oshi, Idu, Uberta, Obagi, and Ibewa], located just north of the plant site, are all non-associated gasfields, so the costs of compressing associated gas will be avoided. Shell says production costs will be relatively low because the gas is of good quality and because only shallow drilling will be required. The project as envisioned at present will only require some 130 billion cubic meters out of Nigeria's proven and probable reserves - mostly discovered by accident in the course of oil exploration - of 2600 bcm.[3]

Both economies of scale and "highgrading" will have an important bearing on the costs of financing. If the financial community sees that a future ANGTS project has been modified, eliminating much of the benefits of economies of scale and/or subjected to "highgrading," it is unlikely to readily embrace such a project except at significantly higher financing costs.

---

[2] Natural Gas Intelligence, December 19, 1988, page 1.

[3] Petroleum Economist, March 1988, page 92.

Thus, the economic assumptions incorporated into the ANGTS project by itself should not be assumed to be readily transferrable to a modified project that at some future date attempts to make use of North Slope gas reserves other than those in the Prudhoe Bay field.

In summary, there is no evidence that sufficient proved and economically transportable gas reserves on the North Slope exist to warrant construction of two major transportation systems in essentially the same time frame.

Issue Two: Will the currently proved Prudhoe Bay gas reserves be needed more by the United States or the Pacific Rim countries?

The present period in the U.S. gas industry is a particularly difficult time for ERA to make a critical decision regarding the future need for Alaskan gas in the Lower 48 states. The U.S. has experienced a long-term period of gas surplus -- the gas "bubble" or "sausage" as it has been termed for several years. Wellhead spot gas prices have recently been in the $1.25 - $1.50 per million cubic feet range. Thus, from the current perspective of the beginning of 1989, the Lower 48 states may not "need" gas whose sponsors quote a tariff of $3.05 delivered to market.

However, the proposed TAGS start-up date is 1996. By that time, at present rates of gas consumption, the U.S. will have consumed a volume of gas equivalent to 79% of our present Lower 48 proved reserves. By then, whether or not we are in surplus will be dependent on the effectiveness of the industry in exploring and developing our remaining gas resource base, not on current perceptions of the bubble.

There are strong indications that the gas bubble period is ending. Within the industry, gas producers are beginning to reactivate plans for future imports of LNG to the Lower 48 states. Increasingly, U.S. gas consumers are looking to Canada as an incremental source of supply, and Canadian gas imports have been steadily rising. Moreover, an interest in long-term contracting is emerging within domestic gas circles. In effect, there are numerous industry "signals" indicating that the U.S. gas market is tightening and that the period of gas surplus is over.

As gas markets move from surplus to more balanced and perhaps even "tight" gas supply/demand conditions, ERA's decision is

particularly difficult given the uncertainties of gas pricing of the coming years. Wellhead pricing under the surplus conditions of recent years has reflected the abundance of gas relative to domestic demand levels and resulted in gas-to-gas pricing competition. In a more balanced gas environment, however, wellhead pricing will be affected by other factors, such as the world price of oil, the availability and price of other energy sources including coal, the level of Canadian gas exports to the U.S., etc.

In addition, U.S. gas pricing is undergoing a major restructuring because of changes taking place under Federal Energy Regulatory Commission Order Nos. 436 and 500 designed to open up the domestic pipeline network to open-access transportation. At this time, the gas industry is in the midst of a major transition in which historical service obligations and merchant functions of gas pipelines are being shifted to gas distribution companies and even directly to gas users. This fundamental restructuring of pipeline rates is far from complete or settled. Gas markets are and will continue to be affected by developments in transportation rate design, but precisely how is difficult to predict since the mechanisms for implementing the new rate structures are still being formulated. For example, the new gas pricing environment will be characterized by such new rate factors as gas inventory charges, standby reserve charges and other, potentially yet unnamed, factors reflecting the unbundling of gas services historically grouped together in a single gas price. But exactly how these new rate features will affect gas pricing in specific regional markets remains to be seen.

There is little evidence that Asian markets need the Prudhoe Bay gas supply any more than we do at present. Table 1 summarizes the committed or accessible gas reserves available to U.S. and Asian markets. The "accessible" exportable surpluses shown in the table are selected from those countries which are the most obvious trading partners for the market in question. It is apparent from the table that the domestic gas reserves, plus contract commitments, plus market-oriented exportable surpluses,provide for substantially greater coverage for Asian markets than do the comparable reserves for U.S. markets. The total (excluding any North Slope commitments) provides 53.3 years coverage for the Asian market versus 10.1 years for U.S. markets. Addition of the North Slope proved reserves to the Asian market would increase its already substantial coverage of its consumption by nearly 13 years. For the U.S., however, addition of the North Slope proved reserves to its relatively much larger market has a much more modest effect.

From this viewpoint, the U.S. has a much more pressing "need" for North Slope gas than Asian markets.

And while the reserves committed or accessible to Asian markets have been increasing at the rate of 6.4 trillion cubic feet (tcf) per year since 1977, they have been decreasing at the rate of 2.1 tcf per year in the U.S.

In summary, the weight of this evidence is that the proved gas reserves at Prudhoe Bay are much more likely to be needed by the United States in the years ahead than they are by Japan, Korea, and Taiwan.

Should the Yukon Pacific Application Be Denied?

The fundamental issue in this application, in our view, is whether the Yukon Pacific project can go forward as designed without foreclosing important energy options for the U.S. as we approach the turn of the century. If this application is approved, it is possible that just when the TAGS project is under way, the ANGTS option is likely to be an economically attractive, necessary supply source for domestic markets. However, a decision now by ERA may preclude the ANGTS possibility forever, given the potential insufficiency of alternative Alaskan reserves to meet domestic market demands and the deleterious impact the TAGS project may have on the economic viability of ANGTS. Thus, it would appear that the burden of proof that the TAGS project does not preempt the U.S. option should rest with the applicant. Absent credible evidence from Yukon Pacific to the contrary, this application should be denied.

TABLE 1

PROVED RESERVES COMMITTED OR ACCESSIBLE
TO U.S. OR PACIFIC GAS IMPORT MARKETS[1]

(Tcf 12/31/86)

	Japan	Korea	Taiwan	Total Pacific	U.S.
Committed to Domestic Markets	1.1	--	0.9	2.0	139.3[2]
Committed on Import Contract[3]					
Alaska (Cook Inlet)	0.2	—	—	0.2	—
Abu Dhabi	1.1	--	--	1.1	--
Australia	6.1	—	--	6.1	—
Brunei	1.8	--	--	1.8	--
Indonesia	10.2	2.0	1.5	13.7	—
Malaysia	5.1	—	--	5.1	--
Canada	--	—	—	—	20.1
Mexico	--	—	--	--	1.6
Remaining Contract Volumes	24.5	2.0	1.5	28.0	21.7
Accessible Exportable Surpluses					
Australia				26.8	—
Brunei/Malaysia				31.9	--
Indonesia				15.5	—
Canada[4]				--	7.7
Mexico[5]				--	0
Subtotal Surpluses				74.2	7.7
North Slope Proved Reserves					
Yukon Pacific Request				16.0	--
ANGTS Project				--	25.0
Surplus				9.0	—
Subtotal North Slope Proved Reserves				25.0	25.0
Total Above				129.0	193.7
Consumption 1986 (adjusted)[6]				1.95	16.7
Ratio Accessible Reserves to Consumption (ex North Slope)				53.3	10.1
(with North Slope)				66.2	11.6

FOOTNOTE PAGE FOR TABLE 1

1 Source of estimates: Based on the supporting detail for Oil and Gas Journal article by James T. Jensen, June 6, 1988, page 38.

2 In Jensen Associates, Inc.'s definition, all U.S. domestic proved reserves are "Committed to Domestic Markets" except those expressly allocated to Frontier, Deferred, Committed to Export, or Marginal. North Slope reserves are treated as "Frontier."

3 Remaining commitments to end of contract.

4 With the abandonment of the surplus test in 1987, Canadian exportable surpluses could rise rapidly reflecting higher depletion rates for proved reserves. This estimate assumes that the Canadian practice of requiring 20-year contracts will be retained and thus the 7.7 tcf is surplus to 20 years of existing contract coverage.

5 Mexico ceased exporting to the U.S. in 1984. "Committed to Export" shows volumes remaining on contract. Given current Mexican policy of retaining gas for use at home, exportable surplus is assumed to be zero.

6 Total Pacific consumption for 1986 is for Japan and Taiwan. Korea had no consumption at that time; however, Asian volumes have been increased to accommodate new LNG projects starting up between 1986 and 1990.

Jensen Associates, Inc. is a consulting firm specializing in planning and economics for oil and natural gas. We are best known for our experience in North American natural gas markets. Our work in this area covers a broad range of evaluations of demand by sector and by region, supply, pricing considerations, and regulatory and political developments. Some examples of studies we have done for clients will give an idea of the range of our experience.

Retainers

We have a number of retainers with clients in both Canada and the United States with an ongoing interest in North American natural gas markets. They include companies involved in gas distribution, transmission and production, and generally focus on issues of demand, supply, price and regulation.

Market Assessments

JAI was the marketability consultant for the Alaskan Natural Gas Transmission System consortium from 1978 to 1981.

We are called on from time to time to do market studies for major gas supply expansion schemes. Among our studies in recent years are two U.S. East Coast LNG import project evaluations as well as two significant Canadian export pipeline expansion proposals. The feasibility of these projects was dependent upon estimates of market volumes and prices.

International Gas Trade and LNG

JAI has been active in international gas studies, such as LNG developments, for example. We were the contractor for the Office of Technology Assessment of the U.S. Congress on "Imported LNG Projects, Supply and Consumption" -- a policy study undertaken in late 1979. An approach which we used in that study to classify world gas reserves as a basis for international trade was utilized by the IEA in its 1982 study entitled "Natural Gas, Prospects to 2000." We have continued to utilize this approach in papers and speeches since that time. These have included speeches before the Oxford Energy Seminar, the Energy Policy Foundation of Norway and the gas trade summary speeches at the 1984 Gastech Conference in Amsterdam, and the 1986 Conference in Hamburg. The most recent examples of these papers on gas trade are a

paper for the Society of Petroleum Engineers and an article in the Oil and Gas Journal.

Over the past ten years, we have undertaken more than a dozen LNG project studies involving sources in Algeria, Indonesia, Qatar, Norway and Trinidad, and markets in the U.S., Canada, Japan and Taiwan.

We assisted one of the major purchasers of Soviet gas in its anticipated arbitration of its contract with the U.S.S.R. We also undertook a study for one of the major oil companies of the outlook for gas markets in Europe and the influence of Soviet gas export policy on that market.

Supply Evaluations

JAI regularly monitors North American gas supply as a part of our general market monitoring efforts. We were the prime contractors to the Office of Technology Assessment of the U.S. Congress in a study entitled "Understanding Natural Gas Supply in the U.S." Periodically, we undertake specific supply studies for clients. An example of this type of analysis would be a study of the supply position of a pipeline as a means of reassuring an LDC purchaser about the quality of the pipeline's long-term supply position.

Pricing and Contracting

Price forecasts for specific client decisions are frequent assignments for JAI. As examples, we have recently undertaken forecasts of natural gas prices for two different electric utilities, including the logic of price formation as it would influence their operations. Several other recent studies required that we develop escalation clauses that will operate effectively in the new era of market-responsive pricing and volatile energy price formation.

Policy

We are frequently called upon by clients to critique policy proposals by regulatory bodies such as the Federal Energy Regulatory Commission. In Canada, we were selected by the Government's Pipeline Review Panel to assist them in their analysis as to how Canada should move towards open transportation and market-responsive pricing. Our specific assignment was to assist the panel in understanding how the U.S. had approached the problem and what features of the U.S. approach Canada should adopt or avoid.

We were actively involved for Canadian clients in evaluating the alternatives to the earlier Canadian single border pricing policy for exports to the United States. We concluded at an early point that variations on the two-part rate design were a preferred option for Canadian policy. We later assisted several clients in testimony

before the U.S. Federal Energy Regulatory Commission when they sought approval of such a pricing formula for their export contracts.

Strategy/Structure

Some of our projects focus on the question of changing industry structure and the strategy which a company should follow in trying to adapt to change. A major example of such a study was one which we recently undertook for a large interstate pipeline system. The company gas marketing activities had been reorganized upon the recommendation of an organizational consultant. We were asked to provide a second opinion on the organization structure, focusing especially on the likely changes in the market and the organizational effect they would have on demands on company marketing activities. We concluded that certain functions would be required of the company in the future but had not been considered because they were not now part of the present market environment. We recommended changes by which the company could respond to the challenges it would face in the future.

Other

Our experience is both North American and international and includes both oil and gas. We have not included in this listing of projects some of our oil-related work. However, our oil-related work gives us the background to judge oil prices and to determine the interaction between oil market developments and natural gas markets.

Mr. Jensen is President of Jensen Associates, Inc., a firm of consulting energy economists in Boston, Massachusetts. He has a degree in chemical engineering from the Massachusetts Institute of Technology and an MBA from Harvard Business School. For eighteen years prior to his establishment of Jensen Associates, Inc., Mr. Jensen was a Senior Staff Member of Arthur D. Little, Inc. Throughout his career, he has concentrated on petroleum, natural gas, and energy economics and their applications to the management of energy-oriented organizations. His major interests have been in the fields of energy planning, economics, and forecasting, and in investment and feasibility decisions in the energy industries.

He has broad experience in international petroleum and natural gas markets and the impact of governmental intervention on their behavior. His clients have included governments of both producing and consuming countries, as well as private and government energy companies and energy consumers.

Analysis of markets, pricing and interfuel competition have formed a major part of his work. He regularly provides his clients with an interpretation of the political, economic and market forces which determine the prices of oil and gas. Through the use of computer models of interfuel competition which have been developed by Jensen Associates, he frequently provides assessments of the likely impact which energy price changes will have on the relative market share for oil and gas, both by sector and by region. He has undertaken natural gas marketing studies for clients throughout the world and has been responsible for oil marketing strategy studies for companies and for governments.

Issues surrounding energy supply form another important element of his work. These include supply forecasts and long-term crude oil acquisition strategy studies for refiner marketers. He has developed an approach for classifying world gas reserves as a basis for world gas trade which is commonly quoted by others.

Investment feasibility has been an important part of his assignments. These have included refinery expansion projects, transportation facilities, petrochemical plants, and liquefied natural gas proposals for projects in Europe, Latin America, North Africa and the Far East, as well as the United States. For corporate clients he has undertaken merger and acquisition, and company organization studies.

He is recognized for his expertise in natural gas supply, demand, regulation and pricing both in the United States and internationally. He has testified on natural gas issues before Senate and House Congressional Committees, before the Federal Energy Regulatory Commission and its predecessor, the Federal Power Commission, as well as many state regulatory agencies.

Mr. Jensen has written extensively on oil and gas matters. His recent papers include *Evolution of Market-responsive Pricing for Natural Gas in the U.S. and Its Effect on Gas Trade (1986); World Gas Reserves and Availability (1986); Factors Affecting Gas-based Industrial Development (1985); Natural Gas Deregulation and the Clash of Cultures (1984); Factors Involved in the Present Oil and Natural Gas Market Instability (1984);* and *Oil's Next Ten Years: "It Won't be Dull" (1983).*

Mr. Jensen has been a regular visiting faculty member of the Oxford Energy Seminar at St. Catherine's College, Oxford. He has also lectured on energy topics at other seminars conducted at Harvard, M.I.T., Northwestern and Oxford. He is a frequent speaker at U.S. and international energy meetings.

Mr. Jensen is a member of the American Petroleum Institute, the Society of Petroleum Engineers, American Chemical Society, Boston Economic Club, and the National Association of Petroleum Investment Analysts.