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ECONOMIC ANALYSIS OF ALASKAN ROYALTY GAS CONTRACTS

a report to

STATE OF ALASKA: THE LEGISLATURE

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Boston, Massachusetts
Washington, D.C.

ECONOMIC ANALYSIS OF
ALASKAN ROYALTY GAS CONTRACTS

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INTRODUCTION

Three contracts for the sale of the State of Alaska's royalty gas from the leases on the Prudhoe Bay oil and gas field have been negotiated by the State of Alaska with Tenneco Alaska, Inc., El Paso Natural Gas Company, and Southern Natural Gas Company. These contracts must be approved by a majority of each House of the Alaska State Legislature. The Legislative Affairs Agency, acting on behalf of the Alaska State Legislature, has retained Jensen Associates, Inc. to perform an economic analysis of the State of Alaska's Proposed Royalty Gas Sales Agreements. The economic analysis of these proposed agreements is presented in this report.

The purpose of our analysis is to determine if the contracts protect the interests of the State of Alaska. In this analysis, we were asked to examine two questions:

1. Is Alaska protected if the El Paso project is not the one selected? and
2. If the El Paso project is approved, does the contract provide favorable value to Alaska?

SUMMARY

Alaska will receive favorable benefits from royalty gas either by obtaining the highest possible price from the sale of gas into interstate markets or for soundly based use in Alaska. Because of the large volumes of royalty gas available and because of the possibility of additional gas discoveries near Alaskan markets for natural gas, the more important question for this analysis appears to be the price that Alaska can receive in interstate markets. Second, it is necessary to analyze the flexibility built into the contract to allow Alaska to use the gas for its own needs.

There is significant uncertainty about the price of the Prudhoe Bay royalty gas. Table I-1 illustrates this range where it shows the possibility of prices ranging from $0.20 to above $2.00 per Mcf. The uncertainties in the value of the gas and thus risks to Alaska are caused in part by uncertainties in energy markets, but much more importantly are caused by the uncertainties surrounding the legislation and regulation of natural gas.

The initial deliveries of Prudhoe Bay natural gas will occur at a time when--in our view--significantly increasing prices for energy world-wide are likely. Between now and 1985, we believe that the Organization of the Petroleum Exporting Countries (OPEC) is not likely to lose control of international oil pricing despite occasional periods of surplus and some degree of internal dissention within the organization. Beyond 1985, however, the possibility exists for sharply higher real world oil prices. This would result from continued growth of world oil demand combined with growing producing capacity limitations in many OPEC countries, thereby creating the conditions for shortage pricing by those few national oil suppliers who can still respond to world demand growth.

Between now and 1985, U.S. energy prices should rise because of (1) OPEC oil prices rising to keep pace with inflation in industrialized countries, (2) a rise in U.S. oil prices to approximate world oil levels as the current domestic price controls are relaxed or eroded, and (3) the U.S. beings to use higher energy prices to foster energy conservation as do Japan and the countries of Western Europe. Beyond 1985, much greater price uncertainty exists, but in our view, rising real prices are the most likely possibility.

The value of Prudhoe Bay gas netted back to the wellhead from No. 2 oil market values in California and the Midwest are shown in Table I-1 for 1980. Because the market price of No. 2 oil is expected to increase, and perhaps sharply, over the

TABLE I-1

RANGE OF POSSIBLE WELLHEAD PRICES FOR PRUDHOE BAY NATURAL GAS

1980

Market Values via El Paso Project*	Dollars per million Btu
Competing with No. 2 oil**	
Mid West	0.94
California	1.22
Competing with coal based synthetic natural gas	
Mid West	2.71 - 3.05
Regulated Values	
Opinion No. 770 National Rate on new gas	
$1.42 plus $0.01 per quarter from October 1, 1976	1.56***
Possible Alaska Area Rate****	0.20 - 0.45

*Assuming F.P.C. staff estimate of gas capital transportation costs and netback value for fuel cost.

**Equivalent Btu value with No. 2 oil giving natural gas a 10 percent form value premium.

***If the prices are regulated using more recent drilling costs and discovery data, the cost based price should rise above that shown here.

****Computed with only Alaska data including associated gas.

twenty-year contract life, the netback market values will be higher than the 1980 wellhead price shown.

The greatest uncertainty about price is caused by uncertainty over legislation and regulation. If new gas is deregulated and Prudhoe Bay gas qualifies as new gas, as it will under some bills, then market value pricing will prevail. If wellhead prices continue to be regulated, Prudhoe Bay prices remain uncertain. Recent national rate opinions by the Federal Power Commission (F.P.C.) have specifically excluded Alaska and Hawaii from both the rates and the cost calculations that underlie the rates. If Alaska is included in the national rates as currently computed based only on non-associated gas, the prices will change little from current calculations because of the small amount of Alaska non-associated gas. However, if the vintaging formula under the most recent national rate decision, (Opinion 770-A), were to prevail, in which well spud-date determined the vintage, then some gas would not qualify for the new gas rate. However, vintaging is not the source of great price uncertainty. If regulation does not include Alaska in the national rate and an area rate is set for Alaskan reserves as the associated gas of Prudhoe Bay sets the possibility for lower wellhead prices. Since some of the costs of exploration and development will be allocated to oil for an associated gas discovery, and the Prudhoe Bay field is large, the costs per Mcf of gas is low as shown in the sample calculation in Table I-1. However, such a calculation assumes that the F.P.C. will depart from its recent tradition of excluding associated gas from its national rate calculations as had been done earlier in F.P.C. history. In any case, regulatory decisions can have great impact upon the value to Alaska of the Prudhoe Bay royalty gas.

CONCLUSIONS

The termination clauses built into the contracts protect Alaska in the event that the El Paso project is not approved or that there is excessive delay in approvals.

If the El Paso project is approved or if the terms of the contract prevail under another pipeline route, then the pricing provisions and the reservation clauses become important. The most important question is how does the contract protect Alaska's interest in the face of considerable price, regulatory, and legislative uncertainty. Our conclusions are:

- Future wellhead prices of Alaskan natural gas will be determined either through regulatory processes as they are now, or through price negotiation should Congress deregulate natural gas.
- In the event of deregulation, the contract will play a significant part in price determination. The pricing clauses with periodic redetermination, assuming a proper clarification of the ambiguity of redetermination relative to Section 6.3, are sound.
- If wellhead price regulation remains in force, the role of price determination will remain with the Federal Power Commission, or possibly with Congress and the contract itself can do little to influence the price. It is important to recognize that the contract has adopted a passive stance, having tied itself to the efforts of the producers in obtaining a ceiling price. Since no real precedent for price setting of Alaskan associated gas exists at present within the F.P.C., and since the strength of the producers' gas is not known, the state might have a stronger future position by setting its own price precedent now in this contract under Section 6.2.
- In addition, there is ambiguity in the interpretation of the price including severance taxes on royalty gas under regulation. This may keep severance taxes or their equivalent from being collected on the royalty gas at a loss of $50-$150 million dollars. The ambiguity needs clarification either in the contract or through Alaskan severance tax legislation.

The clauses reserving gas for Alaska are very good and provide significant flexibility. The State can make both time and location exchanges when they provide a better value for natural gas to Alaska than by selling interstate.

Finally, favorable value of the gas will be brought to Alaska more by action outside the contract in legislation and regulation than by the contract itself.

II. SUMMARY OF CONTRACT

The proposed sales by the State of Alaska of 2.6 trillion cubic feet of Prudhoe Bay royalty gas to Tenneco Alaska, Inc., El Paso Natural Gas Company, and Southern Natural Gas Company are designed to help Alaska in three ways:

1. Promote the construction of a trans-Alaska gas pipeline system, with the associated benefit of making gas available close to people and industry;
2. Establish a gas pricing structure favorable to Alaska for sale of royalty gas outside the State; and
3. Protect future needs for gas within Alaska.

A brief review of the contract mechanisms designed to implement the above goals follows.

PROMOTE TRANS-ALASKAN PIPELINE ROUTE

Article I of the contracts (entitled Support for Trans-Alaska Pipeline) requires both the State of Alaska and the royalty gas purchasers to work actively for the selection of a trans-Alaska gas pipeline system. The provision in Article XI (Conditions Precedent) that the royalty gas contracts may be terminated by directive of the Governor of Alaska if another route is approved appears to give sufficient motivation to the buyer to work hard in its endeavors to seek passage of a trans-Alaska pipeline route. Alaska's interests are adequately protected on this point. Alaska may choose to support any trans-Alaska pipeline route, although the State has indicated a preference for that proposed by El Paso Alaska Company. Alaska may also terminate the contract if pipeline route approvals are not forthcoming by December 31, 1978 or if a route other than El Paso's is approved.

ESTABLISH FAVORABLE GAS PRICING STRUCTURE

In order to obtain favorable prices for Alaskan royalty gas, the contracts establish different pricing mechanisms depending upon the regulatory or non-regulatory status of the gas. Article VI (Price) identifies three regulatory situations which might occur:

Section 6.2: Federal Power Commission has jurisdiction at the time of first deliveries over royalty gas resale rates in interstate commerce;

Section 6.3: No Federal Power Commission rate-regulation exists for royalty gas for interstate resale at the time of first deliveries; and

Section 6.4: Federal Power Commission deregulation occurs after first deliveries of royalty gas have begun.

If Federal Power Commission jurisdiction applies, the initial price of the royalty gas is to be the highest applicable rate allowed and never less than the price paid producers for their gas from the same reservoir for comparable interstate sales. If regulation does not apply, then the initial price is to be the highest interstate price being paid producers for similar sales from the applicable Prudhoe Bay leases.

If deregulation occurs after first deliveries, the price is subject to redetermination with a provision for arbitration in the event that price accord can not be reached. Annual redetermination may occur thereafter at the request of either buyer or seller. In all cases, the gas price is adjustable up or down if the gross heating value is more or less than 1,000 British Thermal Units (Btu's) per cubic foot.

Since no specific prices are established in the contracts, our analysis focusses on three issues:

1. The likely U.S. and world energy marketing context facing Alaskan royalty gas in the period 1980 and beyond. Chapter III examines energy economic trends in the U.S. and world pressures on energy prices in that period;
2. The market value of Alaskan royalty gas at the time of actual deliveries (Chapter III); and
3. Possible pricing formulas that may apply in the event of price regulation existing at the time of royalty gas deliveries (Chapter III).

Two additional aspects of natural gas pricing--vintaging and severance taxes--are considered in our analysis.

Vintaging refers to the date assigned to an interstate gas sale to determine the applicable regulatory price. Severance taxes are state-imposed producer taxes on gas extraction. The implications of vintaging and severance taxes to the contracts are discussed in Chapter III also.

PROTECT ALASKA'S FUTURE GAS NEEDS

Alaska clearly desires to retain future access to Prudhoe Bay gas for internal requirements. Under Article III (Quantity), the State has the right to reduce the quantity of royalty gas for interstate sale by varying percentages throughout the life of the contract. Alaska may retain 25% of the royalty gas for the first five years and increase this amount by 25% in each subsequent five-year period over the life of the contract. Alaska also has the right to change the percentages of royalty gas taken for internal needs upon a 24-month written notice as well as to export products, such as ammonia, manufactured from its retained gas. While the three contracts also contain "take-back" provisions enabling the buyer to recoup the quantities retained by the State to meet internal needs, this applies only if additional surplus royalty gas is available. Chapter IV of this report considers possible situations in which Alaska retains royalty gas for internal usage.

Finally, in reviewing the royalty gas contracts, some concerns arose regarding specific contract language. While relatively minor, these points are outlined in Chapter V. It is also recognized that in the process of negotiating a contract, both parties must "give and take" on the various issues. Since Jensen Associates, Inc. was not involved in the negotiating process, we acknowledge that some of the matters on which we comment here may have been dealt with in the negotiations themselves. Nevertheless, the issues are outlined in the report in accordance with our obligation as consultants.

III. SALE OF PRUDHOE BAY NATURAL GAS

Alaska wants the most favorable price it can obtain for its royalty gas sold into interstate commerce. As we look ahead, we see considerable uncertainty about the price of energy in general and specifically about the price of natural gas in Alaska which may prevail when initial deliveries of royalty gas occur and for the subsequent twenty years over the term of the contracts. These uncertainties were apparently understood in the negotiation of the royalty gas contract. The contract pricing clauses simply state that the price shall be set at the highest price determined for comparable contracts, and if deregulation occurs, periodic price redetermination is established.

The uncertainty in price and thus risks in the payments to Alaska are created by forces outside the contract. These forces are markets and the course of natural gas regulation and/or legislation at the Federal level. This contract can influence the course of markets, regulation or legislation only slightly. However, the Legislature of the State of Alaska needs to be aware of and understand the causes behind these very real uncertainties about the price of Alaskan gas and their economic risk as it evaluates these contracts. Consequently, our evaluation of the contracts focusses more on contractual ability to adapt to changing price circumstances than upon the ability of the contracts to influence the prices.

In order to understand the extent and cause of the uncertainty about price of Alaskan royalty gas, we describe below the movement of energy markets in the United States and the world from 1975 to 1990, market value pricing of Alaskan gas which would prevail if deregulation of the wellhead price of gas were to apply to Prudhoe Bay gas, costs of alternate forms of energy for natural gas pipelines, and the impact and differences in pricing which regulation by a body such as the Federal Power Commission could bring to the price of Alaskan royalty gas.

ENERGY MARKETS IN THE UNITED STATES AND THE WORLD, 1975-1990

The Organization of Petroleum Exporting Countries (OPEC) has demonstrated since late in 1973 that it has considerable power to set the price of crude oil unilaterally in world markets. Western Europe, Japan, and increasingly the United States, as natural gas production declines, are dependent upon this imported oil which is the incremental source of energy in the industrialized nations and tends to set the price of all forms of energy. Consuming nations can influence price through controls or taxes to be more or less than the world market crude oil price. But controlling price below world market levels requires the nation to have its own energy production, as is true of the United States.

OPEC Production and Pricing

Table III-1 is the estimate of the world oil trade to 1985. The growing demands for OPEC oil production make a break-up of the cartel unlikely. We expect the United States to continue to rely upon imported oil, and, thus, be heavily subject to the world price of oil. The production of oil from OPEC nations should increase steadily but within productive capacities. In particular, Saudi Arabia, a country with the largest oil reserves in the world, should be able to accommodate increases in demand without strain to the mid-1980's.

The price of OPEC oil is not expected to decline, rather we expect the oil producing nations to attempt to maintain the value of their oil. As inflation continues in the industrial nations, the price of oil should increase apace to the mid-1980's.

Forecasts of oil, supply, demand and price are subject to an increasing range of error the further into the future the forecast is made. However, the contracts for royalty gas are scheduled to run for twenty years beyond the initial deliveries of gas which should occur sometime between 1980 and 1985.

TABLE III-1

WORLD OIL TRADE

(Million barrels per day)

	1975	1980	1985
IMPORTS			
United States	5.8	11.5	11.5
Western Europe	12.4	12.0	14.0
Japan	4.9	6.0	8.0
Net to Balance 1/	4.3	6.5	9.5
OPEC PRODUCTION			
Total	27.4	36.0	43.0
Saudi Arabia 2/	7.1	10.0	12.0

1/ Includes net imports (exports) of the Non-OPEC developing countries, the Sino-Soviet countries, OPEC internal consumption, stock changes, and adjustments.

2/ Includes 50% of Neutral Zone.

Source: Jensen Associates, Inc.

Thus, most of the gas under these contracts will be delivered after 1985, the time horizon to which most international oil forecasters have recently chosen to limit their estimates. In order to understand how energy prices will behave in the latter part of the 1980's and beyond, it is important to review the likely trends in world oil consumption compared with the development of both non-OPEC and OPEC supply.

Oil will be a major source of energy into the 1990's and beyond. Even though non-traditional energy sources may begin to grow rapidly, they do so from a small base so that continued economic growth needs to be, for some years after 1985, fueled by oil. But as oil demand on OPEC production increases, production capacity limits for most of the OPEC countries could very likely be strained. It is not hard to see oil demand bumping up against capacity constraints most everywhere except in Saudi Arabia after 1985. If this were to happen, the conditions would be set for another dramatic upward shift in the price of oil. It is also possible to envision very effective conservation efforts and accelerated alternate energy supply programs being developed, in which case the strains on OPEC production capacity would not be severe and oil price increases would be moderated. However, it is difficult to envision a decline in OPEC production in the decade following 1985 which would place downward pressure on world oil prices unless the industrialized nations of the world were to sink into depression.

As the time of initial deliveries of royalty gas nears, the post-1985 energy supply and demand balances will become clearer. These forecasts should begin to have a significant impact upon domestic U.S. energy prices and government policy. The post-1985 conditions are unclear today and the range of uncertainty about energy prices is high. However, forces that would create sharply higher prices seem more likely than a worldwide depression that might force oil prices downward.

U.S. Price Controls

At the current time, the price of oil in the United States is controlled by the Federal government at levels below the world price. However, the price for "new" oil is higher than for "old" oil in order to encourage further exploration and the development of additional supplies. The stated intention of the Energy Policy and Conservation Act is to allow the price of oil to increase and eventually for it to be decontrolled. Either as "new" oil becomes an increasing share of supply or oil price is decontrolled, the price of oil will increase more rapidly in the United States than in world markets as the U.S. prices catch up to the world prices.

U.S. Energy Conservation

There is a developing consensus in the United States that the conservation of energy is an important national objective. Currently, there is no equivalent consensus on how this objective is to be reached. There have been some attempts to use engineering standards mandated by regulation or legislation to promote energy conservation such as mileage requirements for new cars. Meanwhile, government policy has concentrated on keeping the price of energy low.

Other countries, such as Japan and those in Western Europe who have a longer history of oil imports than the United States, have relied upon the price system to bring about energy conservation. These nations increase the cost of energy to the consumer above world oil prices by taxation. Energy consumption in Japan and Western Europe is below that of the United States by more than can be explained by a difference in the standard of living. The use of the price system to bring about energy conservation has proven to be successful in other nations.

As the United States develops an energy conservation program, an increasing reliance upon higher energy prices to bring about conservation is to be expected. This, too, should reinforce both the OPEC determined price increases, the price increases of oil and other energy forms in the United States as oil market levels are approached, to bring about an even greater increase in the price of energy for the United States.

Conclusion

OPEC oil pricing, the phase-out of oil price control in the United States or an increasing proportion of "new" oil, and greater reliance upon higher prices to foster energy conservation all point to increased energy prices in the U.S. The extent of these increases is uncertain. However, the greatest uncertainty is about prices in the mid-1980's. The potential for oil demand running hard against world productive capacity exists. Sharply increased prices would result. But, if the industrialized nations can aggressively conserve energy and develop sources other than oil, or if economic growth falters, then OPEC oil production capacity will not be under the same stress.

MARKET BASED VALUES OF NATURAL GAS

In the event of deregulation, market forces would determine the field price of Alaskan North Slope gas. One way to anticipate this price is to forecast the market price of alternate fuels and to netback to the North Slope using the costs of transporting the gas to market. The theory is that the price of natural gas at the market (e.g., Los Angeles) would tend toward a level related to the price of alternate fuels, and that the field price resulting would be the market price less the cost of transmission.

We have computed the netback value of Alaskan North Slope gas based on the market prices of competing alternate fuels in Los Angeles and Chicago. This section describes the method and the results of this analysis.

Number Two Fuel Oil

The calculations which compare natural gas with fuel oil are based on the projected prices of No. 2 oil in Los Angeles and Chicago. In the case of Los Angeles, it was assumed that No. 2 oil would be refined primarily from Alaskan crude, priced to be competitive with Saudi Arabian light landed in Houston. The present price of Saudi Arabian light is $12.09 F.O.B. Ras Tanura. This price can be inflated at 5% per year to 1980 and, with the addition of transportation costs, terminal costs and refinery margins, yields a projected price for No. 2 oil in Houston in 1980. Netting back to Los Angeles via crude pipeline results in a price for No. 2 oil refined from Alaskan crude and delivered in Los Angeles. A 10% premium must then be added to account for the fact that natural gas is often preferrable on a Btu basis to No. 2 oil.

To compute a price for No. 2 oil in Chicago, we added to the price of No. 2 in Houston the cost of transporting the fuel by product pipeline to Chicago. Again we added 10% to reflect a premium for clean-burning natural gas.

In both Chicago and Los Angeles, it was assumed that the relevant price comparison was between No. 2 oil at the refinery rack and natural gas at the city gate. The cost of local delivery to large volume industrial users was assumed to be small and approximately equal for either fuel.

SNG from Coal

Current estimates for the cost of producing gas from coal form a range of between $3.00 and $4.00 per million Btu. To obtain a 1980 price for coal-based SNG, we selected $3.50 as a middle-range figure, inflated it at 8% per year for five years, and added projected transportation costs.

Netback Value

The netback value is computed in the following way. Suppose the projected market price of No. 2 in Los Angeles is $3.50 per MMBtu. Adding 10% results in a market value for natural gas of $3.85 per MMBtu, competing against No. 2 oil. In other words, pipelines could charge gas distributors in Los Angeles up to $3.85 per MMBtu, the price of the competing incremental fuel source. The field price in Alaska is then determined by subtracting from $3.85 the cost of transporting the gas from the field to Los Angeles. If the transport costs were $2.00 per MMBtu, then the price that Alaska could charge for its royalty gas in the field would be $3.85 minus $2.00 equals $1.85 per MMBtu.

It should be noted that transportation costs include the cost of gas used and lost along the respective routes. Consequently, transportation costs vary with the netback value which in turn varies with the projected market price of the competing fuel. In short, the higher the value of Alaskan North Slope gas, the more expensive it is to transport.

Tables III-2, III-3, and III-4 show netback values computed for the El Paso project and the Arctic Gas project separately.

Strictly speaking, netback values show what price would prevail for natural gas (regardless of source) in each market, assuming insufficient gas is available to replace the alternate

TABLE III-2

NETBACK VALUATION OF ALASKAN NORTH SLOPE GAS
BASED ON NO. 2 OIL
1980

(Dollars per million Btu)

El Paso Route

	Price of No. 2 Oil (Incl. Premium)*	- El Paso Transportation Costs**	= Netback Value
Chicago	$3.34	$2.40	$ .94
Los Angeles	$3.10	$1.88	$1.22

Arctic Route

	Price of No. 2 Oil (Incl. Premium)*	- Arctic Transportation Costs**	= Netback Value
Chicago	$3.34	$1.68	$1.66
Los Angeles	$3.10	$1.40	$1.71

*Assumes that the current price of Saudi Arabian light ($12.09) will rise at the rate of 5% per year to 1980 and 7.4% per year from 1980 to 1985. These estimates are representative and merely reflect current expectations.

**Based on average fifth-year cost to the Mid West and California as published by the F.P.C. staff (12/7/76). Estimates assume 2.4 and 2.25 Bcf/d capacity for the El Paso and Arctic systems respectively. Gas lost or used as fuel in transit is valued at the netback value.

NETBACK VALUATION OF ALASKAN NORTH SLOPE GAS
BASED ON NO. 2 OIL
1985

(Dollars per million Btu)

El Paso Route

	Price of No. 2 Oil (Incl. Premium)*	- El Paso Transportation Costs**	= Netback Value
Chicago	$4.59	$2.61	$1.98
Los Angeles	$4.27	$2.08	$2.19

Arctic Route

	Price of No. 2 Oil (Incl. Premium)*	- Arctic Transportation Costs**	= Netback Value
Chicago	$4.59	$1.79	$2.80
Los Angeles	$4.27	$1.50	$2.77

*Assumes that the current price of Saudi Arabian light ($12.09) will rise at the rate of 5% per year to 1980 and 7.4% per year from 1980 to 1985. These estimates are representative and merely reflect current expectations.

**Based on average fifth-year cost to the Mid West and California as published by the F.P.C. staff (12/7/76). Estimates assume 2.4 and 2.25 Bcf/d capacity for the El Paso and Arctic systems respectively. Gas lost or used as fuel in transit is valued at the netback value.

TABLE III-4

NETBACK VALUATION OF ALASKAN NORTH SLOPE GAS
BASED ON SNG FROM COAL
1980
(Dollars per million Btu)

El Paso Route

	Price of SNG Delivered*	- El Paso Transportation Costs**	= Netback Value
Chicago	$5.46	$2.75	$2.71
Chicago	$5.46	$2.41***	$3.05

Arctic Route

	Price of SNG Delivered*	- Arctic Transportation Costs**	= Netback Value
Chicago	$5.46	$1.87	$3.59
Chicago	$5.46	$1.61***	$3.85

*Current estimates place the cost of producing SNG from coal of between $3 and $4 per MMBtu in 1975 dollars. We have used $3.50/MMBtu and inflated at 8% per year to 1980. Cost of transporting SNG assumed to be 32¢/MMBtu.

**Based on average fifth-year cost to the Mid West and California as published by the F.P.C. staff (12/7/76). Estimates assume 2.4 and 2.25 Bcf/d capacity for the El Paso and Arctic systems respectively. Gas lost or used as fuel in transit is valued at the netback value.

***Assumes gas lost or used as fuel in transit is valued at $1.00/MMBtu.

fuels. Of course, if all Alaskan gas were channeled into Los Angeles, saturation would occur and Los Angeles' market price of gas would fall. However, in the broader context of the national market, (which size is currently on the order of 55 billion cubic feet per day), the additional 3.5 billion cubic feet per day anticipated from Alaska may not be sufficient to render uneconomical even the most expensive alternate fuel sources now being contemplated.

Contracts

Section 6.3 of the contracts states that in the event of deregulation, prior to first deliveries of Alaskan North Slope gas, "the initial price for gas delivered hereunder shall be the highest price being paid by any interstate gas purchaser for gas under contracts. . . ." This provision appears adequate to insure that Alaska receives the full netback value based on the appropriate competing alternate fuel source, providing that the North Slope producers have marketed their gas judiciously; and with the price incentives inherent under deregulation, there is every reason to believe that they would do so.

Section 6.4 provides, moreover, for price redetermination in the event that the price of gas is regulated at the time of first deliveries and subsequently deregulated.

These two sections together provide that Alaska receives full market value for its royalty gas under deregulation, providing vintaging allows, whether or not deregulation occurs before or after the date of first deliveries. Moreover, inasmuch as Alaska contemplates taking royalty gas in kind, and selling it in the field, netback pricing serves to illustrate the market price potentially available to Alaska for its royalty gas.

COST-BASED REGULATION OF ALASKA GAS PRICES

In the event the sales of Prudhoe Bay gas contemplated in the contracts are found to be jurisdictional by the F.P.C., the price clause (Section 6.2) provides that

1. ". . . The initial price . . . shall be the highest area, national or ceiling rate allowed to be paid by any interstate gas purchaser to any working interest owner . . ."
2. "The price to be paid thereafter shall be subject to all periodic changes permitted in accordance with the . . . Rules and Regulations of the Federal Power Commission . . . or such other changes in price as may be permitted by any new area, national or ceiling rates . . . which may subsequently be established."

Thus, the value of the contracts depends upon the ceiling price which may be established by the Federal Power Commission. The contracts do not specify or assume that the nationwide rate established by the F.P.C. will apply to the contract sales. On the contrary, the contracts accept in advance, whatever rate-making method the F.P.C. might apply to sales of Prudhoe Bay gas. Moreover, the contracts tie the interests of the State of Alaska to the interests of the private companies producing Prudhoe Bay gas. The State will not receive a price for its royalty gas any higher than the cost-based price which the companies can justify to the F.P.C.

The National Rate and Alaska Gas

The current nationwide wellhead ceiling price for "new" natural gas in the United States is $1.42/Mcf (plus 1¢/quarter beginning October 1, 1976), established in F.P.C. Opinions 770 and 770-A. However, these Opinions and the earlier nationwide rate Opinion 699-H all explicitly excluded the States of Alaska and Hawaii.[1] A simple decision could be made by the Commission to delete the exclusion and thus bring Alaskan gas under the

[1] Title 18, U.S.C., paragraph 2.56a (f).

nationwide ceiling. The difficulty with this approach is that the $1.42/Mcf is a cost-based ceiling price, calculated using cost data from only the lower-48 states. That is, the exclusion of Alaska from the $1.42/Mcf ceiling is not only a legal or procedural fact but also a computational fact. If the F.P.C. were to attempt to establish a single uniform national rate including Alaskan gas, the Commission would likely bring data on the cost of gas production in Alaska into the computation process.

One fundamental assumption underlying Opinions 699-H, 770 and 770-A is that most natural gas produced in the U.S. is from non-associated gas wells (wells which produce gas from reservoirs which do not also contain crude oil). For this reason the Opinions consider data on the drilling costs and drilling footage of gas wells only. All data on oil wells (many of which also produce gas) are excluded. If the F.P.C. were to revise the national rate to incorporate data on non-associated gas wells in Alaska, the national rate would not be much affected. The number of Alaskan non-associated gas wells and the quantity of Alaskan non-associated gas reserves are not large enough (relative to the national total) to have a significant impact upon the calculation of the national rate.

However, the inclusion of Alaska within the national uniform rate may be difficult precisely because of the fundamental assumption stated above, i.e. that most U.S. natural gas is produced from non-associated wells. Such an assumption, some may argue, is inapplicable to Alaska, where over four-fifths of natural gas reserves exist in conjunction with oil. For this reason, there is a reasonable possibility that the Commission will establish a separate area rate for all gas in Alaska or for casinghead gas from oil wells in Alaska.

An Area Price Ceiling for Alaska

The calculation of a wellhead ceiling price for all natural gas in Alaska, or for casinghead (associated-dissolved) gas alone, requires the allocation of costs between oil and gas. During the long history of F.P.C. wellhead price regulation, many methods have been proposed for making such an allocation. Most of these methods have been based upon a combination of two principles:

- That oil and gas may be substituted for each other as sources of energy and are valuable because of their energy content as measured in Btu's, and
- That oil, which has traditionally sold at a higher wellhead price per Btu than gas, should receive a premium value over gas.

A brief review of F.P.C. wellhead price regulation uncovered no instance in which the Commission had actually allocated costs between oil and gas in order to set an areawide ceiling price on associated gas (called "casinghead gas" in the area rate opinions). In setting area price ceilings between 1961 and 1974, the Commission established various categories of gas according to vintage date. The calculation of the price applicable to each vintage category was based entirely upon the costs of non-associated gas production. Newer vintages of gas received higher ceilings than did older vintages, due to inflation of drilling costs and declining sizes of gas discoveries. Casinghead gas was included in the older vintage and was not vintaged in its own right. Thus, "new" casinghead gas received a lower ceiling price than did new non-associated gas.

The most recent case in which the Commission allocated costs to arrive at a separate cost of service for casinghead gas was in the Phillips Petroleum opinion of September 1960, the last of the individual producer rate cases. In the Phillips opinion, the Commission used separate methods for allocating production costs and for allocating exploration costs. Production costs on leases producing both oil and gas were allocated in proportion to the relative costs of producing oil from oil-producing leases and of producing gas from gas-producing leases. Exploration costs (which were viewed as joint costs because, at that time, the F.P.C. did not accept the concept of directional exploration) were allocated first among oil-only leases, gas-only leases and joint-product leases on the basis of net investment in each of these three categories of leases. Then the exploration outlays assigned to joint product leaseholds were divided between oil and gas using a modified Btu method. The number of Btu's contained in crude oil produced from the joint-product leases in the test year was multiplied by 4 as an "economic factor" reflecting the then-prevailing higher market value of oil than of gas. Thus, the following fraction of joint-lease exploration costs was assigned to gas:

$$\frac{\text{Btu's of gas produced}}{(4 \times \text{Btu's of oil produced}) + (\text{Btu's of gas produced})}$$

The Commission stated that "we are of the opinion that the proper economic factor to be applied to the straight Btu content of oil to allocate Phillips' test year exploration costs is 4, so that the cost relationship of finding one Mcf of gas to one barrel of oil will be about 1 to 24."

Estimation of Alaskan Natural Gas Ceiling Price

Keeping in mind the long span of time which has lapsed since the Phillips precedent for separating oil from gas costs, we have, nevertheless, calculated several hypothetical ceiling prices for Alaska natural gas. These were calculated under the assumption that the F.P.C. would set an area ceiling price for the State of Alaska as a whole, with no differentiation within the State. It was also assumed that the Commission would follow a method roughly analogous to the present method used in setting the nationwide rate (that is, the method used in Opinion No. 770-A) with the following modifications:

- Data pertaining to drilling cost, drilling footage and reserve additions would be drawn from Alaska's experience only. Successful drilling cost and footage would include both oil and gas wells.
- Lead times between capital outlays and start-up of production could be considerably greater than those used in calculating the Lower-48 ceiling, and
- Unit costs would be divided between oil and gas on a Btu basis, or a value-modified Btu basis.

Working entirely from published data (the same sources used by the F.P.C. in setting the nationwide ceiling price), we calculated wellhead ceiling prices which ranged from under 20¢/Mcf to about 45¢/Mcf. The higher end of this range was calculated assuming a straight Btu division of oil and gas, which is the most favorable calculation from the gas producer's standpoint. No allowance was made in these calculations for any special capital outlay for waterflood or other enhanced oil recovery operation necessitated by the removal of the natural gas drive mechanism in the reservoir.

F.P.C. Jurisdiction Over Alaska Royalty Gas

The basic presumption of government regulation of an exhaustible resource is that economic rents should be captured by the private consumers of the resource rather than by the private firms or individuals who own and produce the resource. This presumption reflects the present distribution of political power and influence between the two groups, the consumers and the producers. The purpose of setting a ceiling price based upon cost calculations is to carry out this allocation of rents.

The State of Alaska, as a public rather than a private producer and owner of resources, may not be subject to the same political arrangement which underlies cost of service regulation. That is, in addition to the legal argument that a State is not a "person" within the meaning of the Natural Gas Act, there is also an economic and philosophical argument that a State is vested with quite different and much broader social responsibilities than is a private firm. For this reason, the State may be entitled to capture a greater share of the resource rents than has been awarded by the political process to private resource producers. The contracts for the sale of Alaska royalty gas, as they are currently formulated, establish price by reference to a ceiling price established for private producers. Such pricing by reference appears to abdicate the position that the State, even if subject to regulation, should not be subject to cost-based regulation. It would also appear to place the State in the position of accepting a regulated ceiling price established for private producers even if the State is not found subject to regulation.

As the representative of a diverse social group, the State may not wish to bind itself to prices received by private producers, because these prices may be determined without reference to the public nature of the State of Alaska.

VINTAGING

As presently written, the contracts for the sale of Alaskan royalty gas do not mention the possibility that several ceiling prices might simultaneously apply to gas from the Prudhoe Bay area. Such a circumstance could arise from whatever "vintaging" policy is chosen by the F.P.C. to apply to Alaska gas, and could have a significant impact on the value of Alaskan gas.

"Vintaging" refers to the establishment of a date--such as the date of discovery of the reservoir or date of commencement of the well--which separates the produced gas into two (or more) categories for pricing purposes. For example, the current national rate for interstate natural gas is $1.42 (plus 1¢ per quarter) for gas produced from wells commenced on or after January 1, 1975. Gas from wells commenced between January 1, 1973 and December 31, 1974 qualifies for a price of $.93 (plus 1¢ per annum). In this example, the date of well commencement ("spud date") is the vintaging criterion.

At the present time, Alaska is in a unique position. No existing vintaging basis clearly applies to Alaskan gas. Thus, Alaska is limited in its ability to address future vintaging treatment of royalty gas through the terms of the sales contracts. Alaska can, however, strengthen its future position by clearly understanding the implications of vintaging and being prepared to act through regulatory intervention or otherwise at a future date. This chapter attempts to clarify the vintaging issues pertinent to royalty gas contracts.

Vintaging Under the Uniform National Rate

For Alaskan royalty gas to qualify for the highest national rate, under present vintaging methods, the gas must be produced from wells spudded in after January 1, 1975.

The "spud-in" date is the moment of drilling the first foot of a well regardless of the date of completion or recompletion. Well completion refers to the installation of permanent equipment for the production of oil or gas. The date of completion of an oil well or gas well is the date on which the installation of permanent equipment has been completed for the production of oil or gas as reported to the appropriate regulatory agency.

Depending upon the gas field or reservoir drilling development pattern, spud-in date may or may not be a vintaging basis favorable to Alaska. If most gas is produced from wells spudded-in after January 1, 1975, then Alaska may qualify for the highest available national rate for most of its gas if the national rate applies to Alaska. If the royalty share comes from wells spudded-in at a considerably earlier date than the January 1, 1975 cut-off, then Alaska clearly is in a less favorable position vis-a-vis the national rate. At the present time, wells spudded-in on or after January 1, 1973 and before January 1, 1975 receive separate national rate treatment from the F.P.C. while gas from wells commenced prior to January 1. 1973 receive rate treatment under F.P.C. Opinion No. 749 which has established a price of 29.5¢/Mcf nationally for "old" gas. Clearly, the maximization of Alaskan royalty gas revenues will depend on the type of vintaging mechanism allowed under regulation.

Other Vintaging Methodologies

In the evolution of gas pricing regulations, the Federal Power Commission has used various methods for determining the vintage of gas. Other regulatory vintaging methodologies have used contract date, type of gas, date of dedication to interstate commerce, and reservoir discovery date. Table III-5 details the vintaging mechanisms in national and area rate regulation as well as in two proposed 1975-76 deregulation bills.

TABLE III-5

SUMMARY OF NATURAL GAS VINTAGING APPROACHES RELATED TO INTERSTATE PRICE REGULATION

	ALLOWED HIGHEST APPLICABLE RATE FOR:							
	Type of Gas		Qualifying Date for "New" Gas Vintage					
VINTAGING APPROACH	Associated or Oil Well Gas	Non-Associated or Gas Well Gas	Spud-In Date	Recompletion Date	Date of Initial Interstate Dedication	Date of Contract	Date of Reservoir Discovery	RATE ESCALATION
1. National Rate								
a. Opinion 770-A (November 1976)	yes	yes	yes	no	no	no	no	yes
b. Opinion 770 (June 1976)	yes	yes	yes	yes	yes	no	no*	yes
c. Opinion 699-H (December 1974)	yes	yes	yes	yes	yes	no	no*	yes
2. Area Rate								
Permian Basin Opinion 468 (August 1965)	no	yes	no	no	no	yes	no	no
3. 1975-1976 Proposed Deregulation								
HR 10480 Krueger-Broyhill Bill (October 31, 1975)	yes**	yes**	yes	no	yes	no	no	As Per Contract
S-3422 Pearson-Hollings Bill (May 12, 1976)	yes	yes	yes	yes	yes	no	yes	yes

*Date of discovery of a new gas reservoir on acreage previously dedicated to the interstate market was a vintaging criterion.

**If producer is not affiliated with a pipeline.

Jensen Associates, Inc.

Contract date and type of gas were used together in the first area rate vintaging methodology (Opinion No. 468 issued August 5, 1965). In this case, an established date (January 1, 1961) was the dividing date between old and new gas with new gas being that which was sold through a contract dated after the January 1, 1961 date. However, this system also vintaged gas on the basis of whether it was gas well gas or oil well gas. All casinghead gas (or oil well gas) was categorized as old gas; only post-January 1, 1961 gas well gas received new gas treatment. Similar vintaging methodologies were used in other area rates established by the F.P.C. with some variations as to the applicable contract vintaging date. The pricing implications for Alaskan royalty gas if vintaging occurs on a basis comparable to area rate regulation are considered elsewhere in this chapter. Alaska should understand, however, that by stating a contractual willingness to accept an area rate with its inferred vintaging mechanism, it may face future rate rulings that are either unanticipated or clearly less favorable than more recent pricing regulations.

Vintaging on the basis of first sales into interstate commerce (under contracts executed after a specified date) has also been used by the F.P.C. in the first uniform national rate (June 1974). This methodology has been superceded by well commencement date vintaging. Date of first sales into interstate commerce appears to be an attractive vintaging basis. It has a clear disadvantage, however, if the market value of gas is expected to rise over the term of the contract by committing all the gas to a price set when market value was lower.

Conclusions

1. No single vintaging method yet applies to Alaskan royalty gas and Federal Power Commission actions on this are uncertain.

2. Revenues to Alaska for royalty gas sold interstate are highly dependent upon the vintaging method selected.

3. No single vintaging system is clearly superior to all others, although in general, the more gas that falls into the "new gas" category or vintage, the greater are Alaska's opportunities to maximize royalty revenues.

Vintaging Under Proposed Gas Legislation

Numerous proposals to deregulate or reregulate natural gas pricing were introduced into the 1975-76 Congressional Session, and already in the current Congress eleven bills as of this writing have been proposed. Passage of a particular bill at this time is unclear. However, based on 1975-1976 bills, vintaging is likely to remain an issue in current proposed legislation of great economic significance to Alaska.

The importance of future deregulation or reregulation to Alaska's royalty gas contracts is the possibility that there may be multiple vintages applicable to the Prudhoe Bay gas. That is, depending upon the vintage method, there may be a deregulated and a regulated price in effect at the time of first deliveries.

SEVERANCE TAXES ON ROYALTY GAS

It is possible that \$50 - \$150 million[1/] in revenue might be lost to Alaska from an interpretation of price in Section 6.2, 6.3, and 6.4. While the Alaskan severance tax legislation currently does not apply to state-owned royalty interests, the price clause should not preclude by omission the collection of a severance tax or revenue in lieu of severance taxes on Alaskan royalty gas in addition to the base price. Under F.P.C. regulation, the price paid to a producer by a pipeline for the working interest share will be adjusted upwards from the ceiling rate to cover severance tax. This payment for severance tax is in turn fully recovered by the pipeline. If a severance tax on the Alaskan royalty interest is not charged in addition to the highest allowable area, national or ceiling rate under some interpretations of the gas contract pricing clauses, the price for royalty interest gas will be less than the price paid by pipelines for the working interest portion. In the condition that Alaska is not subject to F.P.C. jurisdiction, the royalty gas will be sold at the highest price paid by a purchaser which appears to be wording that would cover severance taxes paid by the working interest holder. Given the amount of money involved, we suggest legal review on the point of collecting severance taxes. The possibility for a low price differential on Alaskan royalty gas may be eliminated in one of two ways:

(1) legislative action to include the royalty interests taken in kind with that production which is subject to a severance tax, or

(2) a change in the contract which sets the price of Alaskan royalty gas at the highest allowable price plus an adjustment in lieu of a severance tax.

1/ For sale of 2.6 tcf at \$0.50 to \$1.50 per million Btu assuming one million Btu per Mcf and a 4% severance tax.

IV. USE OF GAS WITHIN ALASKA

The State of Alaska is permitted to reduce the volumes of gas sold under the contracts. Any reduction may be made on twenty-four months' notice, or up to specified limits on twelve months' notice, provided the gas is to be used for "domestic or industrial" purposes in Alaska.

As presently written, the contracts do not specify whether the withdrawn gas must be for current or anticipated domestic or industrial needs. It is possible that Alaska might predict or foresee a need for natural gas within the State which extends beyond the term of the contract, or an increasing demand for intrastate gas which will eventually exceed the total volume of royalty gas during the term of the contract. We see no contract impediment to a time exchange of royalty gas which might be worked out with the owners of the working interests.

For example, the province of Alberta follows a rule of protecting provincial requirements for a forecast 30-year period before permitting additional interprovincial sales. A similar rule could be applied by Alaska.

As shown in Table IV-1, natural gas consumption in Alaska during 1975 was 66.8 billion cubic feet, none of which came from the North Slope. If the total contracted amount of royalty gas (2.6 trillion cubic feet) were produced uniformly over a 20-year period, the annual volume of royalty gas would be 130 billion cubic feet. Thus, if all additions to intrastate natural gas consumption had to be drawn from the royalty gas in the contracts, then Alaskan gas consumption would have to triple over present levels before all the royalty gas would be withdrawn from the contracts.

Gas utility sales in Alaska grew at an average rate of 12.7% per annum from 1965 to 1975 and at a rate of 12.1% from 1974 to 1975. Total consumption of gas in Alaska rose from

TABLE IV-1

NATURAL GAS CONSUMPTION IN ALASKA

1975

User	Sales by Gas Utilities Bcf 1/	Total Consumption Bcf
Residential	5.6	10.4
Commercial	6.4	8.5
Industrial	.	22.4
Electric Utilities	12.8	19.6
Other	5.9	5.9
Total	30.7	66.8

1/ Bcf = Billions of cubic feet

Sources: U.S. Bureau of Mines, Mineral Industry Surveys; American Gas Association, Gas Facts 1975

42.0 Bcf in 1971 to 66.8 Bcf in 1975 or at an annual rate of 11.6%, as shown in Table IV-2. Growth of the natural gas industry has been from a fairly small base figure, so that a projection of recent rapid growth rates may be unrealistic, at least in areas already well served by gas. However, even if it is assumed that growth continues at the somewhat reduced rate of 6% per annum, Alaska's internal gas consumption would triple in about 18 years. If the slightly faster rate of growth of 10% occurs, consumption will triple in about 11 years. In either case, internal consumption would outstrip the annual volume of royalty gas before the end of the term of the 20-year contract. Moreover, the level of intrastate demand achieved by the end of the contract term could not be sustained by royalty gas from Prudhoe Bay beyond the productive life of that area. However, areas closer to Alaskan gas markets such as the lower Cook inlet may be the source of future growth in natural gas supply.

AMMONIA PRODUCTION

As a part of our economic analysis of the contracts for the sale of royalty gas, we have considered the possibility that Alaska might prefer to export manufactured products which use gas as a feedstock rather than exporting the natural gas itself. The principle argument would be that the value added (wages, salaries, profit) would thereby be retained for the Alaskan economy.

We considered, in particular, industries which are heavily dependent upon natural gas, such as ammonia manufacture. We determined that, if all of the Alaskan royalty gas were devoted to ammonia production, Alaska would then produce about 30% of the present U.S. level of ammonia output. Ammonia production in the U.S., although it is one of the most intensive industrial uses of natural gas, nevertheless consumes only a small fraction (a little over two percent) of total

TABLE IV-2

GROWTH OF NATURAL GAS CONSUMPTION

ALASKA 1971-1975

Use	1971 Bcf 1/	1975 Bcf	Average Annual Rate of Growth
Residential	6.9	10.4	10.3%
Commercial	7.5	8.5	3.1
Industrial	10.6	22.4	18.7
Electric Generation	10.3	19.6	16.1
Other	6.7	5.9	-3.2
Total	42.0	66.8	11.6%

1/ Bcf = Billions of cubic feet

Source: U.S. Bureau of Mines, Mineral Industry Surveys

U.S. natural gas production. The U.S. ammonia market simply could not absorb such a large increment in supply.

Moreover, planned additions to ammonia capacity in the lower 48 states are already quite large, amounting to 3.2 million metric tons per year, or a 22% increase over present capacity. As shown in Table IV-3, principal U.S. markets for ammonia fertilizers are in the Midwest, an area more accessible to ammonia plants in Texas, Louisiana or Alberta than to ammonia plants in Alaska. European markets for nitrogen fertilizer probably could be served more economically from the Persian/Arabian Gulf, and thus may not be a prospective long-run market for ammonia from Alaska.

TABLE IV-3

UNITED STATES NITROGEN FERTILIZER CONSUMPTION

BY GEOGRAPHIC AREA

1974

(In 10^6 Pounds)

	Quantity	Percent of Total
West Coast [1/]	1,301	7.8
Upper Midwest	10,096	60.8
Lower Midwest	3,111	18.8
Atlantic Seaboard	2,084	12.6
Total United States	16,592	100.0

[1/] Includes Washington, Oregon, and California

Source: U.S. Department of Agriculture

V. CONCERNS ABOUT CONTRACT AMBIGUITIES

This chapter comments on several specific details in the royalty gas contracts which appear to need clarification. Each point below is keyed to the section of the contract pertinent to the issue. We have suggested possible remedial actions in each case.

1. ARTICLE III (QUANTITY); SECTION 3.7(a):

This section refers to the terms under which the buyer may purchase additional quantities of surplus Alaskan royalty gas in the event that Alaska has previously implemented its option to remove contract gas for intrastate use. Section 3.7(a) continues to be applicable for a period of five years after expiration of the term of the contracts.

The governing price of surplus royalty gas offered to buyer after expiration of the contract and in the event of no other interstate bona fide purchasers is unclear. This section states only that,

> "In the event there are no other interstate bona fide purchasers, the price shall be the price then being paid by Buyer for gas purchased under this Agreement." (Underscoring inserted.)

Contract clarification of the applicable price is needed in the event deliveries have already been completed under the contract and no outside interstate purchasers exist.

2. ARTICLE VI (PRICE); SECTIONS 6.3 - 6.5:

Section 6.4 (deregulation after commencement of first gas deliveries) clearly provides for a price redetermination to occur as outlined in Section 6.5. Section 6.3, however, which provides for an initial price in the event of non-regulation existing at the time of first deliveries does not contain a price redetermination clause. Since Section 6.5 makes specific reference only to Section 6.4, it is unclear that price redetermination will also occur in the event Section 6.3 is operative. Insertion of a clause in the contracts indicating that a price redetermination will occur in the event Section 6.3 applies is suggested.

3. <u>ARTICLE VI (PRICE)</u>:

This Article of the contracts does not address a pricing situation in which the <u>initial</u> gas sales are not subject to F.P.C. regulation but, <u>later</u> in the contract term, <u>become jurisdictional</u>. Such a scenario could occur as a result of (1) judicial appeal of an initial F.P.C. ruling; (2) deregulation of gas prices conducted on a temporary or experimental basis, such as was proposed by President Carter during the election campaign; or (3) Federal action overriding the F.P.C. (e.g., creation of a general price and wage control policy).

APPENDIX A

TABLE 1

F.P.C. NATIONAL RATE RULINGS

F.P.C. Opinion No.: 699

Date Issued: June 21, 1974

Definitions of "new" gas:

(1) Sales of natural gas in interstate commerce made from wells commenced on or after January 1, 1973.

(2) Sales of natural gas in interstate commerce made pursuant to contracts executed on or after January 1, 1973 for

(a) gas not previously sold in interstate commerce (except under specified F.P.C. certificates); or

(b) where the sales were formerly made pursuant to permanent certificates of unlimited duration under contracts which expired by their own terms on or after January 1, 1973.

Applicable Rate: 42¢/Mcf with 1¢/annual escalation beginning January 1, 1974

F.P.C. Opinion No.: 699-H

Date Issued: December 4, 1974

Definitions of "new" gas:

(1) Sales of natural gas in interstate commerce from a well or wells commenced on or after January 1, 1973.

(2) Sales made pursuant to contracts for the sale of natural gas in interstate commerce

(a) for gas not previously sold in interstate commerce prior to January 1, 1973 (except under specified F.P.C. certificates); or

TABLE 1 (continued)

F.P.C. NATIONAL RATE RULINGS

(b) where such sales are initiated on or after January 1, 1973 provided the sale has not been certificated under the F.P.C.'s optional procedure.

(3) Sales made pursuant to contracts executed prior to or subsequent to the expiration of the term of the prior contract where the sales were formerly made pursuant to permanent certificates of unlimited duration under such prior contracts which expired of their own terms on or after January 1, 1973, or pursuant to contracts executed on or after January 1, 1973, where the prior contract expired by its own terms prior to January 1, 1973.

(4) Gas produced from newly discovered reservoirs located upon acreage previously dedicated to interstate commerce under a contract dated prior to January 1, 1973, shall have the rate determined by the date of reservoir discovery in lieu of the contract date.

Applicable Rate:	50¢/Mcf and 1¢/annual escalation beginning January 1, 1975

F.P.C. Opinion No.:	749
Date Issued:	December 31, 1975
Definitions of "old" gas:	Sales of natural gas in interstate commerce for resale from a well or wells commenced prior to January 1, 1973.
Applicable Rate:	23.5¢/Mcf prior to July 1, 1976; 29.5¢/Mcf on and after July 1, 1976. (This rate does not supercede existing higher area rates nor other specified F.P.C. established rates.)

TABLE 1 (continued)

F.P.C. NATIONAL RATE RULINGS

F.P.C. Opinion No.:	770	
Date Issued:	July 27, 1976	
Definitions of "new" gas:	(1)	Sales of natural gas in interstate commerce for resale from a well or wells commenced on or after January 1, 1975.
	(2)	The sale is made pursuant to a contract for the sale of natural gas in interstate commerce for gas not previously sold in interstate commerce prior to January 1, 1975 (except under specified F.P.C. certificates), where the sale is initiated on or after January 1, 1975, provided that no certificate for the subject sale has been issued under the optional procedure.
Applicable Rate:	$1.42/Mcf and 1¢/Mcf per quarter commencing October 1, 1976	
Definitions of 1973-1974 gas:	(1)	Sales of natural gas in interstate commerce for resale made from a well or wells commenced on or after January 1, 1973 and on or before January 1, 1975.
	(2)	The sale is made pursuant to a contract for the sale of natural gas in interstate commerce for gas not previously sold in interstate commerce on or after January 1, 1973 (except under specified F.P.C. certificates), where the sale is initiated before January 1, 1975.
Applicable Rate:	$1.01/Mcf	

TABLE 1 (continued)

F.P.C. NATIONAL RATE RULINGS

F.P.C. Opinion No.:	770-A
Date Issued:	November 5, 1976
Definitions of "new" gas:	Sales of natural gas in interstate commerce for resale from a well commenced on or after January 1, 1975.
Applicable Rate:	\$1.42/Mcf and 1¢/Mcf per quarter escalation beginning October 1, 1976.
Definitions of 1973-1974 gas:	Sales of natural gas in interstate commerce for resale made from a well commenced on or after January 1, 1973 and prior to January 1, 1975.
Applicable Rate:	93¢/Mcf and 1¢/Mcf annual escalation beginning January 1, 1977

(NOTE: IN BOTH OF THE ABOVE DEFINITIONS, WELL DATE IS DEFINED AS COMMENCEMENT OR SPUD-IN DATE REGARDLESS OF DATE OF COMPLETION OR RECOMPLETION.)