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HIGHLIGHTS

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Public Hearing Held on FERC Rulemaking Proposal for Statewide Exemptions from Incremental Pricing

On 2/5/80 a public hearing was held on the FERC's proposed rulemaking (RM79-47) to provide statewide exemptions from incremental pricing provisions of Title II of the NGPA. The hearing was presided over by FERC Commissioners Hall and Holden, and various staff members were also in attendance. Participants were divided into three panels representing state utility commissions, industrial gas users and gas distributors. Of the three groups, more overall support for the proposed rulemaking was expressed by the state commissions.

The Commission originally requested comments on the need to institute a rulemaking proceeding for consideration of statewide exemptions on 7/3/79. Various rounds of comments were filed over the next four months. Most comments generally favored the establishment of a rulemaking, although a few parties either opposed or would postpone consideration of statewide exemptions. Certain comments advanced specific proposed alternatives for statewide exemptions while others stressed the need for flexibility that would allow for alternative state ratemaking techniques. Also, various comments stressed the possibility of inequities resulting from a statewide exemption procedure and urged that FERC exercise extreme care in formulating a rule on this issue.

In its notice of proposed rulemaking (issued 12/21/79), the Commission distinguished between the following two types of state actions which could result in exemption from incremental pricing: (1) state-level incremental pricing -- in which a state sets the price of natural gas to nonexempt users at the federally established alternative fuel cost ceiling; and (2) statewide alternatives to incremental pricing -- in which an alternative state plan is instituted which departs from the FERC rules either with regard to the formula by which surcharges are apportioned among nonexempt users or the manner in which the maximum surcharge absorption capability (MSAC) is computed. Any state taking the first course of action would eliminate any MSAC of nonexempt users in that state. The Commission concluded that it should not and legally cannot prevent states from substituting state-level incremental pricing through increased rates to nonexempt users for incremental pricing at the interstate pipeline level. In addition, the Commission is willing to entertain statewide alternatives to incremental pricing.

With respect to state-level incremental pricing, the FERC noted that if a state raises the rates and charges to nonexempt users to the alternative fuel ceiling, their MSAC becomes zero so that they no longer contribute to recovering the incremental gas cost account of the interstate pipeline supplier. The effect of this is to cause the entirety of revenues collected from nonexempt users to remain within that state. Because its rules operate at the interstate level, the Commission continued, incremental surcharges paid by nonexempt users in one state will contribute to a reduction in amount of purchased gas costs to be recovered from exempt users served by the pipeline, regardless of the state in which those exempt users are located. Hence, the Commission said, some parties submitting comments argued that state-level incremental pricing is unfair, and there should be state-by- state balancing of incremental pricing benefits to all exempt users. Moreover, the Commission added, other parties noted that some states had practiced a policy of pricing low priority users at or near alternative fuel prices prior to passage of the NGPA, thus creating an existing disparity of state pricing policies.

The FERC concluded that these differences "pose an issue that transcends incremental pricing and . . . Congress had no intention of neutralizing these imbalances through incremental pricing." Furthermore, the Commission continued,

action by states to raise nonexempt user prices to the alternative fuel ceiling "is fundamentally consistent with the purposes of incremental pricing." The thrust of Title II is to increase the cost of gas in price-sensitive industrial uses. With respect to nonexempt uses, surcharge passthrough to the burner tip is required. With respect to exempt users, Congress intended that incremental pricing mitigate the impact of rising wellhead prices on residential and other customers. "Because it is within the capability of states practicing state-level incremental pricing to use any revenues derived from non-exempt users to offset rates and charges to exempt users, it is the Commission's expectation that states will cause this Congressional intent to be realized."

On the question of reporting requirements under state-level incremental pricing, the Commission proposed to eliminate such requirements on the ground that local distribution companies would otherwise "have to make monthly reports of aggregate MSAC's to their pipeline suppliers, even though these MSAC's will be zero." As to statewide alternatives to incremental pricing, the Commission decided not to attempt at this time to define or limit the types of state programs that merit consideration, but "to provide a broad measure of flexibility and creativity to states seeking exemptions from incremental pricing." The Commission intends to treat any formally proposed statewide alternative plan as a proposed rule. Thus, it will be noticed for comment and analyzed by the Commission as to whether the underlying purposes of Title II of the NGPA will be advanced. The FERC would then determine whether to submit the proposed state plan for Congressional review pursuant to Section 206(d)(2) of the NGPA, or discontinue the proposed rulemaking. (See REPORT NOS. 1216, pp9-10; 1228, pp24-28; 1230, p18; 1236, pp15-19; 1241, pp1-2.)

State utility commissions submitting formal statements included the California Public Utility Commission, Minnesota Public Service Commission, New York Public Service Commission and the Wisconsin Public Service Commission.

The California PUC "strongly" supported the proposed rulemaking in most respects, including the "fundamental premise . . . that rules providing for statewide exemptions from incremental pricing are in the public interest," and "the FERC's interpretation of the NGPA as giving the agency statutory authority to provide for such exemptions." The CPUC noted that the NGPS clearly permits states to increase gas rates of nonexempt customers to the alternative fuel ceiling. The conferees made clear that "'a state regulatory agency could . . . raise prices to be paid by incrementally priced industrial facilities to levels higher than the levels required by this Title. The conferees have not mandated such a practice; nor has it been precluded. State law is not preempted in this case and states may wish to place more of the cost of service onto a particular class of industrial users ....'" Thus, the CPUC said, Congress anticipated that some states might wish to raise rates to nonexempt customers to levels above the Federal alternative fuel ceiling or determine alternate fuel costs differently from the FERC's method. Moreover, the CPUC added, "Section 205 only prohibits states from lowering rates to nonexempt users below the Federal level, but said nothing about whether states are precluded from raising those rates."

The CPUC also discussed whether the NGPA requires states to use the increased revenues from incrementally priced users to offset rates and charges to exempt users. As to revenues recovered from non-exempt customers up to the level of the Federal alternate fuel ceiling, the CPUC said the states are prohibited from rebating such money to nonexempt customers. Hence, unless the utilities were permitted to retain these excess revenues, the only choice is to use them to offset rates and charges to exempt users. However, as to increased revenues collected from non-exempt customers whose rates may exceed the federal ceiling, Congress

made no judgment. Since Congress intended that the states retain their traditional authority over retail ratemaking, the state utility commission should continue to have discretion to determine the extent and manner of such mitigation of gas costs to residential and other high priority customers.

The CPUC also found the Commission's proposal to eliminate reporting requirements under state-level incremental pricing to be "workable"; "wholeheartedly" agreed with the proposal to permit states to develop alternatives to the Federal incremental pricing program; and opposed treatment of formal submissions of state- wide alternative plans as a proposed rule. In this last connection, the CPUC suggested that such procedure "ultimately may be less manageable and may meet with more Congressional opposition than a generic rule with broad guidelines under which each state could qualify on its merits."

The Wisconsin PSC and The New York PSC generally agreed with the positions taken by the CPUC. Wisconsin, however, sought Commission clarification with respect to (1) whether a state has the option to return revenue collected above the alternate fuel price to exempt customers; (2) whether a class of customers, rather than individual customers, should be the criterion for rate design under alternative state plans because of different state regulatory procedures; and (3) whether the three-tier alternative fuel cost approach (involving use of price ceilings for No. 2 fuel oil and high and low sulfur No. 6 fuel oils) should include a fourth tier for propane, whose price is between Nos. 2 and 6 oil.

Wisconsin also supported generic rulemaking rather than treatment of a formally proposed statewide alternative plan as a proposed rule for separate Commission approval and Congressional review. First, Wisconsin explained, the Commission has the expertise over Congress in these matters. Second, a generic approach would avoid "political tradeoffs" between large and small states. Also, the generic approach would ease administrative burdens generally.

The Minnesota PSC contended that the Commission's "reduced AGA approach" prescribed in Order No. 49 has the effect of encouraging some states "to attempt to pick the pockets of their neighbors," thereby forcing neighboring states to adopt statewide plans in self-defense. These plans, however, may be detrimental to many exempt rate payers in the affected states. Specifically, the Minnesota PSC explained, states with a relatively large proportion of non-exempt industrial load may determine that MSAC dollars collected within the state will exceed the dollar benefits to the state's exempt rate payers through the reduced PGA. If so, these states will be induced to adopt plans which will capture MSAC dollars within the state by requiring local distribution companies not to pass incremental surcharge collections back to the interstate pipeline suppliers, but instead to credit those collections to their own exempt rate payers. However, Minnesota continued, such plans will conflict with the objectives of the NGPA in two ways. First, since higher prices to non-exempt industrial users are dictated by state action, these users will no longer have any motivation to try to restrain pipeline bidding. Secondly, while exempt ratepayers in states adopting such plans will obtain greater benefits from crediting of MSAC dollars within those states than they would receive from reduced PGA rates of interstate pipeline suppliers, exempt users in other states will receive a lesser reduction in PGA rates than otherwise. Hence, incremental pricing under FERC procedures will result in ratepayers in states without state plans (especially states without much industry) subsidizing exempt ratepayers in states with state plans. Moreover, Minnesota added, since exempt customers in states with state plans will enjoy lower rates than similiar customers in states on the FERC plan (other things being equal), they will have less incentive to conserve and may therefore bring more pressure on pipeline suppliers to purchase increased volumes at high

prices.

In Minnesota, it was noted, only three of fourteen regulated utilities purchasing gas from Northern Natural Gas Co. (the state's only domestic pipeline supplier) have incrementally priced load under Phase I of the incremental pricing program. Therefore, adoption of a state plan to retain MSAC dollars within Minnesota would benefit exempt customers of the three utilities, but adversely effect exempt customers of the eleven other distributors. For this reason, a state plan "seems a poor solution."

In order to correct the inequities from state-wide exemptions as contemplated by the FERC, the Minnesota PSC suggested amendment of Order No. 49 to provide that customers in any state which adopts a plan restricting the flow of MSAC dollars to the State's pipeline supplier be charged the pipeline's full PGA rate, not the reduced PGA rate. This amendment would leave states free to adopt state plans but would "remove the push into state plans inherent in the allowance of double dipping." Moreover, by removing the need to adopt a state plan, more states would remain on the FERC's plan, which in turn would both increase the ability of industrial customers to place pressure on pipelines to bargain for lower prices and ensure benefits to exempt ratepayers in all states.

The arguments raised by Minnesota were the subject of extended discussion and debate, as well as probing by Commissioner Hall and various staff members. While conceding the possible negative effect of the "reduced PGA approach" on certain exempt customers under the conditions described by Minnesota, the representatives of the other state commissions could not foresee that the significance thereof was such to require adoption of Minnesota's proposal. Describing the matter as "trivial," the Wisconsin PSC argued, among other things, that the incremental pricing provision of Title II are geared to "classes of customers" not to "state boundaries."

The Commission's proposed rulemaking received both support and opposition from members of the gas users panel. The Process Gas Consumers Group (together with The American Iron and Steel Institute and The Georgia Industrial Gas Group) charged that Title II of the NGPA "is both unsound and unwise and should be repealled . . . ."However, if exemptions thereunder are to be established, state level incremental pricing plans should not be allowed to take effect automatically unless they meet clearly defined criteria to protect both nonexempt and exempt uses as envisioned by Title II, and should not relieve a state and its local distributors from reporting requirements under the NGPA. Also, so-called "innovative state plans" should be subject to individual proceedings (as proposed by the Commission) to determine whether they meet prescribed standards and are otherwise non-discriminatory.

More specifically, PGC asserted that state level incremental pricing plans should not automatically be exempted under Title II. "In the states' frantic rush to take steps to protect their perceived economic and political self-interest by zeroing MSAC's, there has sometimes been a tendency to overlook the fact that the non-exempt industrial gas users within each state are paying the bill for this exercise. The Commission seems to believe that zero MSAC plans subject nonexempt users to nothing more than is required by Title II. The fundamental flaw in this reasoning, however, is that Title II does not require that nonexempt gas users automatically pay gas rates equal to the costs of alternative fuels as do zero MSAC plans. The statute provides, rather, that such users pay up to the alternative fuel cost level. Thus, if a gas supplier has more surcharge absorption capability on its system that it has incremental costs to pass through as surcharges,

the nonexempt users on that system will pay only a pro rata share of the suppliers' incremental gas costs - i.e., rates less than the applicable alternative fuel cost ceiling."

Currently, PGC continued, available information indicates that incremental gas acquisition costs will far exceed the surcharge absorption capability of nonexempt users. However, future oil increases or enactment of the three-tier fuel cap (or both) will likely lead to pipeline surcharges below the applicable fuel cap in certain cases. Under such circumstances, a statewide plan which permanently prices gas to nonexempt users at the alternative fuel cap without the flexibility to reflect lower surcharges permitted under the Act defeats two critical purposes of Title II. First, by raising nonexempt industrial rates above those required by the statute, the risk is increased of industrial load loss and related price increases to exempt users. Second, such rates would defeat the "market-ordering" purpose of Title II to encourage pipelines to moderate their pursuit of high cost gas to prevent nonexempt prices from reaching a level whereby nonexempt users may switch to other fuels.

PGC observed that more than half the states have adopted or may adopt a zero MSAC plan, including those with large numbers of industrial users and those whose industrial rates have been historically low in comparison with oil prices. If these states price nonexempt users at the fuel cap when the pipeline surcharge would otherwise be below it, nonexempt industrial rates in states without zero MSAC plans will be pushed up to the fuel cap as well. Since states at the fuel cap have zero surcharge absorption capability, a pipeline is forced to levy a greater percentage of its surcharges on non-zero MSAC states, bringing them closer (or even up to) the cap. The MSAC of the latter states will, in turn, rapidly disappear, eventually leading to zero MSAC within those states too. "As a consequence of this 'boot strap' effect, all states whether they have a state level plan in effect or not, will end up pricing nonexempt users at the fuel cap even though the pipeline surcharges might have been insufficient to bring those prices up to the fuel cap in the absence of such state plans."

This "boot strap" effect, under which state plans exert "a powerful, but distorting, influence on nonexempt gas prices in <u>all</u> states," PGC declared, illustrates how statewide plans "result in a nationwide game of musical chairs overriding the more fundamental ratemaking goal of establishing retail rate structures on the basis of cost of service and without undue preference or discrimination among consumers." To the extent that some states fail to obtain statewide exemptions from Title II, PGC continued, consumers in such states - both nonexempt and exempt - will be forced effectively to subsidize gas consumption in other states which succeeded in obtaining statewide exemptions and which are served by the same interstate pipeline. Accordingly, the PGC urged the Commission to reject any state plan unless it contains a "no greater harm" provision, whereby it will terminate in the event that nonexempt users begin paying more for gas under the state plan than would pay under the federal plan.

Both the <u>Fertilizer Institute</u> and the <u>Glass Packaging Institute</u> emphasized that any state level incremental pricing program must apply to only nonexempt users, and must exempt all agricultural uses of natural gas exempted by Title II of the NGPA. Both also expressed concern that through state level incremental pricing programs, a state might attempt to impose incremental pricing on an agricultural user which, by law, should be exempted from incremental pricing. Agricultural users which have been exempted by the NGPA, the Fertilizer Institute declared, "must have the benefit of that exemption, whether incremental pricing is administered directly by the Commission or under a state level incremental pricing program."

The Glass Packaging Institute also challenged the Commission's failure to provide a mechanism to ensure that increased revenues derived from nonexempt users are used to offset rates and charges to all exempt users as contemplated by Congress, instead of merely "expecting" that the states would conform to such intent. Rather than proceeding through a generic approach, the states must be required to seek approval of their own incremental pricing plans. Otherwise, the Commission will have no way of knowing which end users are in the exempt or nonexempt class. Moreover, maintenance of all statutorily prescribed exemptions must be a criterion to be satisfied by a state before any exemption from the Federal incremental pricing program would be granted.

On the gas distributor panel, Pacific Gas & Electric Co. generally supported the proposed rulemaking, while the Columbia Distribution Companies and Brooklyn Union Gas Co. opposed it. Pacific Gas & Electric argued that benefits which may be derived from statewide exemptions include (1) a more precise application of alternate fuel price ceiling criteria to avoid fuel switching, thus maximizing benefits to high priority customers; (2) orderly integration of incremental pricing with existing industrial rate tariffs; and (3) provision for alternative approaches to the setting of industrial gas rates which at present are proscribed by incremental pricing regulations.

With respect to the avoidance of fuel switching, PG&E explained that while alternate fuel ceiling prices developed by the Energy Information Administration for all parts of the country are expected to avoid loss of gas load through fuel switching, there is no certainty that load loss will not occur because ceiling price may be inferred when EIA has too small a sample in a given region. This uncertainty would be lessened, PG&E said, if state regulatory agencies were to determine the appropriate alternate fuel price ceiling.

With respect to integration with existing tariffs, PG&E noted that incremental pricing now poses an intergovernmental conflict - two agencies are simultaneously charged with regulating rates and conditions of service for industrial customers. Rates to classes of service other than industrial customers are also affected since federal regulations regarding industrial gas rates must be considered in order to derive a distributor's overall revenue requirement. Another result (at least for PG&E) is that for the first time, a number of customers are required to deal directly with a regulatory agency over terms and conditions of service rather through the serving utility. In situations like this, there is "tremendous opportunity" to simplify rate administration and eliminate a regulatory jurisdictional conflict by merging state and federal regulation at the state level through a statewide exemption plan.

Turning to alternative approaches to industrial rates, PG&E observed that in most jurisdictions, rates and conditions of service are based on a number of factors and, at various times, are designed as incentives to accomplish certain objectives. With implementation of incremental pricing, every state commission and distributor is precluded from any approach to setting industrial gas rates that would be inconsistent with incremental pricing, regardless of the merits of the alternate approach. "A statewide exemption plan could logically be formulated on the basis of an alternate approach to the setting of industrial gas rates, subject to FERC guidelines."

PG&E urged that exemptions be granted only to states which have an incremental pricing plan which can be sufficiently monitored to show compliance with the objectives of Title II. States should be required to demonstrate that a substantial portion, if not all, of nonexempt customers as defined in Title II are

incrementally priced, that a minimal amount of fuel switching is taking place, and that the alternative fuel price ceilings being used are reasonable. Otherwise, proceedings to terminate the states' exemption should be initiated.

In regard to the extent to which increased revenues from incrementally priced users may be used to offset rates and charges to exempt users, PG&E stated that Section 205 prohibits states from rebating money to nonexempt customers up to the level of revenues determined by the alternate fuel ceiling. However, revenues collected from nonexempt customers exceeding this ceiling may be allocated at the discretion of the state regulatory body.

The Columbia Gas Distribution Companies opposed the procedure for establishing incremental pricing exemptions or "innovative" alternative state plans because it would lead to "burdensome, confusing and inconsistent state proposals and FERC rulemaking proceedings." To the extent that one or more states adopts a divergent approach to incremental pricing, Columbia explained, it will become impossible to accurately analyse or formulate FERC incremental pricing procedures on an aggregate basis. "Columbia believes that the proposed regulation would encourage the submission of such plans and that the proposed provision for establishment of statewide exemptions should be deleted from the Commission's final regulations." Columbia supported the proposal insofar as states which have implemented incremental pricing may obtain a waiver of recordkeeping and reporting requirements. However, since certain state plans implementing incremental pricing at the state level would continue only until implementation of FERC's Phase II regulations or until the three-tier alternate fuel ceiling price goes into effect, Columbia urged that recordkeeping and reporting exemptions be on an interim basis so as to allow continuing Commission review of state activity and its impact on the FERC incremental pricing mechanism.

Brooklyn Union Gas Co. asserted that under the FERC's Phase I incremental rules, local and statewide restructuring of distributor rate designs and cost allocations to eliminate MSAC's, has frustrated the passthrough of incremental pricing surcharges. The result has been a "non-program which has effectively written Title II out of the NGPA."

Brooklyn Union suggested that (1) the city gate delivered cost of gas should be used as a base from which MSAC's are calculated; (2) state and local jurisdictions should authorize offsetting rate adjustments to levels at which the total delivered cost of gas to industrial facilities does not exceed the lesser of the city gate cost plus the incremental pricing surcharge, or the appropriate alternate fuel cost; and (3) exemptions should be authorized where, and to the extent, a state or local agency can demonstrate that some form of incremental pricing was in effect prior to enactment of the NGPA.

FERC Publishes Alternative Fuel Price Ceilings for February 1980; Other Incremental Pricing Developments

On ~~1/23/80~~ 2/27/80 the FERC published high sulfur No. 6 fuel oil prices for the 48 contiguous states to serve as alternative price ceilings in implementing first phase incremental pricing regulations during the month of ~~February~~ March 1980. The ~~No. 6~~ March ceilings ~~were~~ developed by ~~the Energy Information Administration pursuant to FERC Order Nos. 50 and 51 (RM79-21) from data collected for large volume residual fuel oil sales in November 1979)~~ EIA December

~~The alternative fuel ceilings for February~~ ranged from a low of ~~$2.38~~ $2.54 per MMBtu for the state of ~~Alabama~~ Washington up to $3.~~36~~ 62 for Vermont and $3.~~23~~ 69 for New Hampshire. Compared with alternative fuel ceilings published for ~~January,~~ February, the ~~February~~ March levels are higher in ~~28~~ 26 states ~~and slightly lower in 20~~ -- between 30 + 40 mills in several states. ~~The ceilings for 29 states were developed by EIA or a regional basis because of the possibility that publication of state ceilings might disclose company specific information. (See REPORT NO. 1241, p8; 1242, p8)~~ more than half

In addition, pursuant to Order No. 49, the FERC published four threshold prices to be used by interstate pipelines and local distribution companies in calculating purchased gas costs subject to incremental pricing. For the month of ~~February,~~ March ~~the threshold prices are:~~ (1) $1.~~138~~ 250 -- applicable to new natural gas, ~~natural gas under~~ interstate rollover contracts, new on-shore production well gas, new LNG imports, and purchases under Section 311 ~~of the NGPA,~~ (2) $2.~~381~~ 404 (the ~~NGPA~~ Section 102 maximum lawful price) -- applicable to new natural gas imports and stripper well gas; (3) $1.~~299~~ 562 (the ~~NGPA~~ Section 109 maximum lawful price) -- applicable to natural gas produced from the Prudhoe Bay area of Alaska; and (4) $7.~~260~~ 410 (130% of No. 2 fuel oil in New York City) -- applicable to Section 107 high cost ~~natural~~ gas.

* * * * *

During the course of the past few months, numerous applications have been filed by pipelines, distributors and nonexempt industrial users under Section 502(c) of the NGPA for various types of adjustments from incremental pricing regulations and/or for interim relief under Section 1.41(m) of the Commission's Rules of Practice and Procedure.

On 2/5/80 the Director of the Commission's Office of Pipeline and Producer Regulations denied a request by Arkansas Louisiana Gas Co. (SA80-50) for relief from incremental pricing filing requirements. Arkla stated that only about 30 of its some 700,000 retail customers are nonexempt industrial users subject to incremental pricing, that these thirty customers are expected to account for less than 2% of total projected sales on Arkla's system in 1980, and that the maximum surcharge to the 30 customers would be "infinitesimal" at approximately 23 cents per month. Akla therefore contended that imposition of an incremental pricing surcharge would constitute a "harsh and unjustified" penalty on its few nonexempt customers, while producing virtually non-existent benefits to other customers.

The Director of OPPR held that Arkla failed to demonstrate either a need for an adjustment to prevent or alleviate a special hardship or unfair distribution of burdens, or a need for interim relief, since the Company's situation is similar to that of most gas utility systems covered by first phase incremental pricing provisions. The Phase I provisions, the Director noted, focused on a class of customers, without reference to the number of nonexempt customers on any given utility system. Further, the number of nonexempt customers may increase with

adoption of Phase II incremental pricing regulations and with issuance of further rules which may lower the 300 Mcf/d cutoff level for exempting small boiler fuel users. Therefore, any question of unfair distribution of burdens to Arkla's approximately 30 nonexempt customers is not properly at issue. Moreover, OPPR observed, Arkla's "reduced" PGA filing which became effective 1/1/80 reflects estimated incremental surcharges of $2.0 million for the first quarter of 1980, or an average surcharge of $66,433 per nonexempt customer.

On the other hand, the Director of OPPR has granted interim relief -- pending disposition of applications for adjustments under Section 502(c) -- to (1) Southern Union Gas Co. (SA80-33) from reporting MSACS of industrial users in certain discrete service areas which do not receive interstate gas directly or indirectly; (2) New Jersey Natural Gas Co. (SA80-34) from the requirement to allocate the MSAC of its only nonexempt customer to all of its pipeline suppliers, thereby permitting assignment of the entire MSAC to the pipeline supplier which provides all of that customer's gas; (3) Valley Gas Transmission Inc. (SA80-44) from incremental pricing filing and accounting requirements, and instead permitting Valley's three interstate pipeline purchasers to treat Valley's incrementally priced volumes as though purchased directly by them from Valley's producer suppliers.

The Director of OPPR on 12/7/79 also granted interim relief to Midwestern Gas Transmission Co. and Great Lakes Gas Transmission Co. (SA80-11) exempting an aggregate purchase of 132 Bcf of Canadian gas to be imported over a short term period ending 10/1/80 from incremental pricing regulations. All of the gas involved is sold to Tennessee Gas Pipeline Co., Northern Natural Gas Co., and Natural Gas Pipeline Co. of America. Midwestern and Great Lakes asserted that they had no incrementally priced acquisition costs other than those potentially attributable to the 132 Bcf in question, and that application of incremental pricing requirements to this 132 Bcf would impose an inequitable and unnecessary hardship on their customers. In the event that the Commission should deny the requested exemption, Midwestern and Great Lakes requested that incrementally priced acquisition costs of the 132 Bcf be attributed directly to Tennessee, Northern and Natural.

Finally, the Director of OPPR granted interim relief to Vertac Chemical Corp. (SA80-63) which requested expansion of the "process fuel" portion of the Section 206(b) definition of "agricultural use" to include boiler fuel consumption of natural gas when required in the process of manufacturing fertilizer or agricultural chemicals.

Several other requests have been filed under Section 502(c) for essentially company-wide exemptions from incremental pricing filing requirements by Lone Star Gas Co. (SA79-4), Pacific Gas Transmission Co. (SA80-21), Gas Gathering Corp. (SA80-38), South Texas Natural Gas Gathering Co. (SA80-42), Carnegie Natural Gas Co. (SA80-45) and North Penn Gas Co. (SA80-46), among others. Most of these requests cited negligible volumes of gas subject to incremental pricing. Lone Star, for example, said it had only two nonexempt customers on its system. Alabama Gas Corp. (SA80-37), by contrast, noted a danger of nonexempt industrial load loss due to competitive bidding by local fuel oil suppliers, with consequent increased rates for exempt customers, and hence requested permission to implement (subject to the approval of the Alabama Public Service Commission) an incremental pricing mechanism providing needed flexibility to meet this competition.

Energy Secretary Duncan Discusses Transition from Oil-Dependent to Energy-Diversified Economy; Projects Slight Increase in Natural Gas Consumption and Reserves

On 1/30/80 Secretary of Energy Charles W. Duncan -- in testimony before the Joint Economic Committee -- discussed the nation's transition from an oil-dependent economy to an energy-diversified economy, and estimated consumption and availability of various fuels through 1985.

In the short-term (the next five years) the world will continue to rely heavily on oil, Secretary Duncan said, which supplied 60% of the world's energy in 1979. The most readily available and economical source of energy for this period is conservation. In the mid-term (1985-2000), the world will move away from an energy system dependent on oil towards coal and coal-derived synthetics, solar technologies, oil shale, unconventional gas supplies, and nuclear power. In the long-term (beyond 2000), the world will move further in the direction of renewable energy sources and advanced nuclear technologies.

Secretary Duncan emphasized the Administration's intent to "rely as much as possible on market forces to bring about this transition. Large scale commercial utilization of new energy technologies will and should be largely the responsibility of private enterprise." Meanwhile the Administration intends to provide "a stable commercial and regulatory climate ... ." Among other things, he explained, there is underway a "careful review of the Department's existing regulations to eliminate those that have outgrown their usefulness. We expect to publish shortly a list of regulations that we intend to eliminate. We are also going to publish a schedule for deregulation so that the September 1981 expiration of existing regulatory authority will be met smoothly and on schedule."

However, Secretary Duncan emphasized, "markets alone cannot reduce our dependence on foreign sources of oil quickly enough." There are public benefits to import reductions such as restraint on increases in oil prices that result from lower U.S. demand and reduced vulnerability to supply disruptions. Therefore, Secretary Duncan continued, "the Government must act to reduce the quantities imported below what market forces are likely to accomplish. The Department seeks to rely on regulation only as a last resort and as required by current statutes. There are a number of ways to stimulate conservation and increase the domestic energy supply without imposing additional regulatory burdens on the economy. Voluntary initiatives, buttressed by appropriate economic incentives and information, are preferred methods for reducing oil imports and changing our energy balance."

Turning to projections of various fuels, Secretary Duncan noted that while natural gas consumption in 1979 remained about the same as in recent years at about 19 Tcf, it will increase slightly by 1985 to 20-21 Tcf, despite continued declines in conventional lower 48 state production. Most of this increase he explained will be due to increased use of gas imports, Alaskan production and some gas from unconventional sources. "The substantial rise in drilling activities already apparent due to recent natural gas legislation will increase reserves in the next few years, forestalling somewhat the projected decline in gas reserves and production."

Total U.S. production of oil, including natural gas liquids, will remain near current levels of 10-million barrels per day through 1985. Even with decontrol and high world oil prices, production in the lower 48 states will decline during the decade, offset somewhat by increased production from new sources of oil such as Alaska, offshore oil and enhanced oil recovery. U.S. net demand for oil is forecast at 16 to 18 million barrels per day in 1985, slightly below the 1979 level of 18.4 million barrels per day.

Secretary Duncan also observed that (1) the growth in consumption of electricity -- which increased by about 3% in 1979 to about 2.1 billion kilowatt-hours -- will depend on future growth of the nuclear-generated share of electricity, which has been reduced in the aftermath of the Three Mile Island accident; (2) coal consumption -- which grew in 1979 by more than 50 million tons to about 700 million tons -- will increase to about 900 million tons by 1985; and (3) renewable energy sources -- which together with solar contributed about 5 quads to energy supply in 1979 --will increase 20% by 1985.

Great Plains Gasification Associates Conditionally Accepts Certificate to Go Forward With Coal Gasification Project

On 2/4/80 Great Plains Gasification Associates (CP78-391) accepted the certificate provided by Opinion No. 69 issued 11/21/79 -- as modified by Opinion No. 69-A issued 1/21/80 -- to go forward with a proposed coal gasification project in Mercer County, North Dakota designed to produce an average of 125,000 Mcf/d of high BTU gas from lignite.

In Opinion No. 69, a Majority of the FERC (Commissioners Sheldon and Hall) 1/ concluded that the Great Plains project is required by the public convenience and necessity to demonstrate the economic, commercial, regulatory and environmental feasibility of coal gasification, and that costs of the project could be borne by ratepayers of the five sponsoring pipelines -- especially since no means are available at the present time to obtain government financing support. However, the Majority conditioned approval on continued involvement of the five sponsors and on restructuring of the project's financing if government support for high-cost energy projects becomes available in the near future. With certain modifications, Opinion No. 69 also accepted most of the tariff and financing provisions proposed by the project's sponsors, including consumer guarantees of debt investment in all circumstances and equity investment in most circumstances. The Majority made clear, however, that this "atypical sharing of costs and risks" was justified only by the demonstration benefits of the Great Plains Project.

Among other specific rulings, the FERC Majority (1) approved recovery of both debt and equity investment from ratepayers in the event of project abandonment, subject to receipt of authorization for any abandonment prior to the initiation of service (after which time Section 7[b] would apply) and subject to a standard of "prudence" in the case of equity investment; (2) rejected automatic tracking of project costs in sponsoring pipelines' rates, directing instead that the pipelines submit cost-revenue studies similar to those required to support PGA rates; (3) concluded that a proposed surcharge during construction to ratepayers of the sponsoring pipelines -- designed to recover interest expense on debt, financing charges, return on equity and related taxes, and similar carrying charges incurred by Great Plains under its coal purchase agreement -- is a reasonable approach to assist financing in light of various safeguards adopted in the decision; (4) approved rolled-in pricing for the coal gasification gas; and (5) adopted a 13% equity rate of return to apply during the construction period and the first 12 months of operation, after which the equity return level will be subject to review on a three-year basis. (The sponsors sought a 15% rate of return on equity.)

1/ Commissioner Holden dissented to Opinion No. 69, and Chairman Curtis did not participate.

In Opinion No. 69-A, the Majority largely denied rehearing, stressing again various types of "information" benefits to be obtained from construction of the Great Plains plant as a demonstration project. However, the Commission made certain clarifications and modifications at the request of Great Plains Associates. Among other things, the Commission elaborated on the nature of the surcharges to recover costs during construction. At the same time, the Commission continued to defer determination of a procedure for tracking of costs after the in-service date until more information is available respecting operation of the plant. (See REPORT NO. 1237, App. pp.1-12; 1241, pp.17-19; 1245, pp.2-5.)

Great Plains Associates conditioned its acceptance of the certification accorded by Opinion No. 69 on Commission approval of various tariff documents -- including gas purchase agreements, funding agreements, and tracking of project costs on a current basis both during and following construction -- which are necessary to implement financing arrangements. Toward this end, Great Plains suggested a conference with Staff at an early date -- prior to filing of the revised agreements and tariffs -- in order to explain the purpose and importance, from a financing standpoint, of present definition and approval of the pipeline tracking mechanisms. Such conference, Great Plains stated, would enable all parties to present an acceptable tracking provision for Commission approval contemporaneously with other tariff documents.

In response to Great Plains' request, a conference with Staff has been scheduled for 2/19/80.

INGAA Seeks Cancellation of Oral Argument on NGPA and Other Policy Issues Involved in Long-term In-place Sales of Reserves

On 2/5/80 the Interstate Natural Gas Association of America filed a petition requesting the Commission to cancel oral argument scheduled for 2/19/80 on the "broad range" of NGPA and other policy questions involved in applications by Natural Gas Pipeline Co. (CP77-71 et al) and three other pipelines to transport south Louisiana gas purchased in-place by General Electric Co. to GE plants located in Indiana, Kentucky and Maryland. The transportation is for a term of ten years. INGAA asserted that if the Commission feels a need to formulate a policy of general applicability with regard to the transportation of industry-owned reserves, it should do so pursuant to its rulemaking authority rather than in an adjudicative proceeding.

On 3/1/77 the Commission authorized the transportation here involved conditioned upon a reduction of term from ten to two years. Natural, GE and several other industrial users petitioned for rehearing of the two-year limitation, contending, among other things, that such restriction was inconsistent with prior Commission orders authorizing transportation of gas owned by industrial customers for periods commensurate with the life of the reserves involved. The FERC granted rehearing on 12/30/77 and set the pipeline applications for hearing. On 5/18/78 the FERC responded to questions certified by Administrative Law Judge George Lewnes as to the scope of pending proceeding. The Commission ruled, among other things, that the proceeding should encompass policy issues raised by long-term transportation of all industry-owned gas however acquired (as opposed to only reserves purchased in-place by industrial customers).

In an initial decision issued 3/1/79, Judge Lewnes called attention to the possibility that the use of in-place transactions as involved in this proceeding might lead to evasion of pricing provisions of the Natural Gas Policy Act. Accordingly, he urged the Commission to "declare all in-place transactions malum prohibitum. Conjunctively, it should summarily dismiss all applications filed after the Natural Gas Policy Act became effective which seek to have transported volumes acquired under in-place transactions."

In its notice of oral argument, the Commission said that the existing record is adequate to consider specific factual circumstances involved in the pending applications, but it "may choose to consider and decide the broader policy issues surrounding the transportation of industry-owned reserves however acquired." Accordingly, it requested oral argument on the following specific issues: (1) whether Title I of the NGPA implicitly prohibits in-place sales of reserves, and whether a unit price therefor can be determined with reasonable certainty at the time of sale; (2) whether industry acquisition of in-place reserves will circumvent the legislative scheme embodied in the curtailment provisions of the NGPA; (3) the impact of industrial purchase, exploration and development of gas reserves on system gas supply; (4) whether pipeline capacity is or will be threatened by transportation of industry-owned reserves, and whether NGPA curtailment priorities should be adopted; and (5) whether the length of the long-term transportation certificate should be decided on a case-by-case basis, for fixed terms established by rule or by some other method. (See REPORT NOS. 1138, pp18-19; 1157, pp16-17; 1199, pp33-35; 1245, pp8-9.)

In its petition to cancel the oral argument, INGAA noted at the outset that adjudicative proceedings have two principal characteristics -- the submission of evidence subject to cross-examination, followed by a determination on the record. Such proceedings are designed to solve factual issues but are not adapted to determine issues of law and policy except when they turn on disputes of fact. The questions propounded in its notice scheduling oral argument did not turn upon disputes of fact in this proceeding. Therefore the adjudicatory procedure is an improper forum to consider these broad policy questions.

Instead, the proper forum is a rulemaking which, according to the Administrative Procedure Act, involves "'the promulgation of concrete proposals, declaring generally applicable policies binding on the affected public... .'" This, INGAA stressed, clearly ties in with the Commission's statement in its notice of oral argument that it may choose to consider and decide the broader policy issues surrounding the transportation of industry-owned reserves however required. Through a rulemaking proceeding, INGAA concluded, the Commission could base its final action on comments from all interested persons and not just those who are party to this proceeding. "Certainly all those to whom the policy would apply are entitled to submit their comments and suggestions to the Commission before the policy is final. This, too, is fundamental."

FERC Staff Director Grants Special Hardship Adjustment Under NGPA Authorizing Southern Union to Increase Gathering Charge

On 1/28/80 the Director of the FERC's Office of Pipeline and Producer Regulation granted an application filed on 8/31/79 by Southern Union Gathering Co. (SA79-24) for an adjustment under Section 502(c) of the NGPA to collect an increased gathering allowance of 19.274¢/Mcf for gas purchased and resold to El Paso Natural Gas Co. and Southern Union's intrastate affiliate, Gas Co. of New Mexico, from the Kutz and San Juan areas, New Mexico. Southern Union's previous gathering charge was 11.2743¢/Mcf. The Director concluded that Southern Union has incurred substantial operating and economic losses at the current gathering rate, which requires the adjustment called for in Section 502(c) "to alleviate special hardship, inequity or unfair distribution of burdens."

Southern Union petitioned on 8/31/79 for a Staff adjustment granting relief from its 11.2743¢ gathering charge following a series of FERC orders which rejected proposed increases in gathering rates (RI79-23) to 19.274¢ filed 12/11/78 under Section 4 of the Natural Gas Act. The Commission concluded that these filings should have been submitted under the adjustment provisions of Section 502(c) of the NGPA. In an order on rehearing issued 8/23/79, the Commission noted that, although Southern Union is not engaged in production of natural gas and instead purchases gas from producers for resale after gathering to El Paso and GCNM, the company is classified as an independent producer. That classification was determined in 1972 after a full hearing. Hence, Southern Union's sale to El Paso represents a "first sale" as defined under Section 2(21) of the NGPA. The Commission further stated that gathering charges applicable to "first sales" are governed by Section 110 of the NGPA and Part 271, Subpart K, of the Interim Regulations implementing the NGPA. Under the Interim Regulations, the gathering charge for gas committed or dedicated to interstate commerce on 11/8/78 (for which a just and reasonable rate was in effect on that date) ~~is limited~~ to the allowance contained in the commission national rate opinions, ~~or~~ (1¢/Mcf in this instance), ~~Hence,~~ the Commission declared, the balance of Southern Union's present 11.2743¢ gathering allowance is not permitted under the Interim Regulations and may be recovered only under Section 502(c) of the NGPA.

In the 8/23/79 order, the Commission permitted Southern Union to recover a Section 110 gathering allowance of 11.2743¢ with respect to sales to El Paso pursuant to Section 502(c), and directed that any gathering charge in excess of 11.2743¢ be requested by Southern Union under Section 270.202 of the Interim Regulations (pertaining to resales) which allows inclusion in resale rates of production- related costs authorized under Part 271, Subpart K, and provides for applications for adjustments under Section 502(c).

Pursuant to the above directive, Southern Union requested an adjustment under Section 502(c) authorizing collection of a 19.274¢ gathering charge for sales to both El Paso and GCNM as of 12/11/78, the date of its rate filings under Section 4 of the Natural Gas Act which were rejected by the Commission. At the current gathering allowance of 11.2743¢/Mcf, Southern Union declared, it was suffering a significant net operating loss -- estimated to exceed $750,000 for the year ending 5/30/79. For the seven months ended 7/31/79, the company's actual total net operating loss was $1.8 million.

On 9/28/79 the Director granted interim relief to Southern Union to collect the increased gathering allowance subject to refund -- effective from 9/28/79 rather than 12/11/78 as requested, and without prejudice to final disposition of the application for adjustment under Section 502(c) of the NGPA. (See REPORT NO. 1229, pp19-20.)

In the instant order, the director observed that Southern Union's status is unique in that it does not fall clearly within the category of either a producer or a pipeline, although it has been found jurisdictional under the Natural Gas Act. In 1972, the Director explained, Southern Union was classified as an independent producer, although "in most respects it does not have the characteristics of an independent producer, nor has it been treated as one." In this case, Southern Union's economic interest in the production is only 2.8%, and its system costs were not included in the area rate proceedings in which a gathering charge was calculated by the Commission. Also, Southern Union's filed-for-rates when granted under the Natural Gas Act represented full recovery of costs. At the same time, the Director continued, Southern Union does not have the characteristics of a pipeline, although its system consists of about 800 miles of line connecting with some 1,000 wells. Instead, Southern Union's primary purpose is gathering of gas for its affiliated distributors, with its only jurisdictional sale being excess volumes to El Paso.

In deciding the merits of Southern Union's application for adjustment in the gathering charge under the Section 502(c) of the NGPA, the Staff employed a cost of service approach rather than an out-of-pocket test because of Southern Union's "unique" status and because the function it performs more closely resembles that of a pipeline rather than an independent producer. Furthermore, the Director added, this methodology was used in determining Southern Union's rates under the Natural Gas Act and the company has designed its operations and made investment decisions based upon this treatment.

More specifically, the Director said, Staff's cost of service used the requested gathering charge of 19.2740¢/Mcf, but differed from the cost of service filed by Southern Union in certain respects, including, among others, the use of actual cost data taken from books and records of the company for the period 10/1/78 through 9/30/79 rather than calendar 1978 data. The results indicate that during the period 10/1/78 through 9/30/79, ~~Southern Union incurred~~ a net operating loss of ~~some~~ $1.8 million and an economic loss of ~~some~~ $5.1 million at the ~~current~~ 11.2743¢/Mcf gathering charge. ~~Had Southern Union been collecting the requested~~ 19.2740¢/Mcf gathering charge, the ~~Director added,~~ it would have recieved an after-tax return of $1.6 million, ~~which~~ equates to an 11.88% overall rate of return on rate base and a 15.36% rate of return on common equity (~~using~~ the capital structure of its parent, Southern Union Co.).

Based upon Staff's study, the Director concluded that Southern Union incurred substantial operating and economic losses at the current effective gathering rate of 11.2743¢/Mcf, and that a Staff adjustment of 7.999¢/Mcf is necessary to assure that the company recovers its costs of operation plus its investment and a reasonable return thereon. In this last connection, the Director further concluded that ~~the~~ a 15.36% rate of return on common equity ~~is~~ within a zone of reasonableness bounded by the rate of return on common equity (13.25%) accorded ~~its~~ pipeline affiliate (Western Gas Interstate) and the rate of return on common equity (16.98%) allowed independent producers. The Director made the adjustment effective 8/31/79, the day on which Southern Union filed for the Staff adjustment, rather than retroactive to 12/11/78 as requested.

(See Rep. Nos. 1229, pp 19-20; 1247, pp 14-15.)

FERC Denies Rehearing of Order Directing Repayment of Gas Illegally Diverted from Interstate Sale Prior to Enactment of NGPA

On 2/5/80 the FERC denied rehearing of an 11/8/79 order which directed Texas Oil and Gas Corp. (CI79-41) -- holder of acreage originally leased to Christie, Mitchell & Mitchell Co. which made sales in interstate commerce to Valley Gas Transmission, Inc. from 1960 to 1962 when production ceased -- to repay Valley for gas delivered in intrastate commerce to Delhi Gas Pipeline Co. and Lo-Vaca Gathering Co. from newly completed wells on the acreage involved up until the effective date of the Natural Gas Policy Act (12/1/78). TXO was further directed to file a production report and payback plan by 12/10/79 and, together with Valley, to file briefs on pricing of the payback volume.

The Commission's order issued 11/8/79 was in response to Valley's petition filed 12/10/78 for an order enforcing the certificate obligation imposed on Christie, Mitchell & Mitchell in 1960 to deliver to Valley all natural gas produced from certain acreage in the Hinnant Field, Live Oak County, Texas at depths down to and including 6,500 feet. Mitchell ceased sales from this acreage in 1962 but did not seek abandonment authorization. Twelve years later, in 1974, TXO obtained lease rights to the subject acreage and, during the eight-month period 6/1/77 - 1/30/78, completed at least six new wells and commenced deliveries into the intrastate systems of Delhi (an affiliate of TXO) and Lo-Vaca. Valley asked the Commission to order TXO to (1) deliver to Valley any and all future production from the dedicated acreage unless and until abandonment authorization is obtained; and (2) pay back to Valley volumes equivalent to gas produced from the dedicated acreage (down to and including 6,500 feet) that was not delivered to Valley since TXO acquired its interest in this acreage.

The Commission concluded in the 11/8/79 order that the Supreme Court's decisions in California v. Southland Royalty Co. (435 U.S. 519) and United Gas Pipe Line Co. v. Billy J. McCombs (No. 78-17) were controlling up until enactment of the NGPA. The commencement of deliveries by Mitchell to Valley, the Commission explained, created a federal service obligation which continues to attach to all gas covered by the certificate until abandonment authorization is granted under Section 7(b) of the Natural Gas Act. Thus, the initiation of deliveries by TXO to Delhi and Lo-Vaca constituted "an unlawful diversion of gas from interstate commerce." Effective 12/1/78, however, the Commission concluded that TXO's gas was removed from interstate dedication by Section 2(18)(B)(iii) of the NGPA (the so-called "Southland" exclusion provision) which excepts from the definition of "committed or dedicated to interstate commerce" any gas which would otherwise be committed or dedicated by reason of the action of any person or successor in interest (other than by means of any reversion of a leasehold interest) if, on 5/31/78, (1) neither that person nor any affiliate had any right to explore for, develop, produce, or sell such natural gas; and (2) such natural gas was not being sold in interstate commerce (within the meaning of the Natural Gas Act) for resale.

Subsequently, on 12/14/79, the Fifth Circuit affirmed a U.S. District Court decision dismissing TXO's request for a declaratory order to quiet claims by Valley and the FERC that the above-described gas produced from acreage in the Hinnant Field previously leased to Mitchell remained dedicated to interstate commerce until receipt of abandonment authorization. The Fifth Circuit agreed with the District Court that interstate dedication of the gas continued even though the acreage in question had not been produced for fifteen years and TXO had no connection with the original leaseholder. The Fifth Circuit also denied TXO's motion to stay the FERC's order of 11/8/79, observing that TXO could seek rehearing of that action before the Commission. (See REPORT NOs. 1239, pp.15-16; 1241, pp.27-28.)

FERC Applies Recent Court Rulings in Orders Involving Rollover Contract Rate Treatment

On 1/22/80 the FERC issued three orders on rehearing of prior rulings in 1976 or 1977 denying rollover contract rate treatment.

One action granted rehearing of a 12/28/76 order which denied a request by CRA, Inc.(CI63-708, RI76-514) to charge the Opinion No. 699-H new gas rate of 51¢ for sales to Northern Natural Gas Co. from a well in Schleicher County, Texas which was reclassified by the Texas Railroad Commission in 1975 from a gas well to an oil well. At the time, the gas was dedicated to Northern under a 1962 contract covering residue gas attributable to any gas well gas produced within a specified area which encompassed the subject well. Following the reclassification, CRA and Northern amended the 1962 contract to include residue sales attributable to casinghead gas. CRA claimed that sales under the amended contract qualified for the "new" gas rate either as old gas sold for the first time in interstate commerce after 1/1/73 or as old gas sold under a replacement contract resulting from termination of the prior contract due to reclassification of the well. In the 12/28/76 order, the Commission rejected both claims. CRA's sale of residue gas was not a new sale, the Commission stated, because the gas involved had been sold to Northern since 1966. "Reclassification of a well by a state agency is not, in and of itself, sufficient to justify abandonment of service of such well, and gas sold from a well after such reclassification is not of a different vintage than before." The Commission further concluded that CRA could not rely on the replacement contract policy because the original contract had not expired of its own terms. Even though the original contract did not cover oil well gas, the primary term of the original contract is nevertheless the controlling consideration, "not the term of the contract as prematurely terminated in some fashion." (See REPORT NO. 1092, p. 29.)

In granting rehearing, the FERC cited the Tenth Circuit's decision of 4/23/79 in Getty Oil Co. v. FERC (No. 77-1993) which reversed the Commission's denial of the new gas rate for certain sales under a replacement contract because the original contract had not run its full primary term but rather had terminated prematurely upon triggering of a pressure decline clause. The Court said the Commission's holding in that case that a contract must run its full primary term in order to qualify for "rollover" treatment represented a new interpretation of the replacement contract policy which was first announced in Opinion No. 770-A issued in November 1976 and should not be applied retroactively to contracts expiring before that date. (See REPORT NO. 1208, pp.22-23.) Applying the above rationale, the FERC concluded in the instant order that reclassification of the well in 1975 -- an event not within the control of the parties -- effected termination of the original contract and that CRA thereby became entitled to the rollover rate for residue sales from oil well gas.

The Commission's two remaining orders issued 1/22/80 on rehearing reaffirmed prior denials of rollover rate treatment. In each instance, the FERC held that the Tenth Circuit's Getty decision did not apply because the original contract had terminated prematurely as a result of events within the control of the parties.

In one order, the FERC rejected a rate increase from 19.79 to 55.66¢ filed by Texas Oil and Gas Corp. (Rate Schedule No. 64) for sales to Michigan-Wisconsin Pipe Line Co. under a 1975 contract replacing a 1960 contract which was alleged to have expired (before the end of the twenty-year primary term) upon release of certain acreage in settlement of a court suit charging TXO with a breach of lease agreement due to lack of production. The Commission concluded that the terminating event -- a settlement agreement entered into by the seller, TXO, and the lessors -- was within the control of TXO, even though TXO may have been under pressure by reason of the lawsuit to enter into the settlement.

The other order reaffirmed a condition limiting sales by Getty Oil Corp. (CI77-70) to Michigan-Wisconsin under a 1976 replacement contract to the Opinion No. 749 flowing gas rate of 29.5¢ on the ground that the original 1956 contract had expired only because of inability of the parties to agree on a price following the end of the fourth five-year period. Since this was an event entirely within the control of the parties, the Commission again held the Getty decision did not apply. Rather, the FERC cited a Fifth Circuit decision of 3/20/78 (Superior Oil Co. v. FERC, 569 F.2d 971) which affirmed the Commission's rejection of proposed increases to the national new gas rates under a similar factual situation. (See REPORT NO. 1150, p.29; 1177, p.7.)

FERC Amends Order Approving Construction of Portion of Western Leg of ANGTS to Increase Size of Pipeline; Other ANGTS Developments

On 1/31/80 the FERC amended its order of 1/11/80 approving construction of the first 160 miles of the Western Leg segment of the Alaska Natural Gas Transportation System between Kingsgate, British Columbia and Stanfield, Oregon (just below the Washington-Oregon border) so as to increase the pipe size from 36 to 42 inches in diameter. The Commission's order conforms to a decision of the Secretary of Energy determining such increase in pipeline size based upon an "optimistic outlook for substantial Alaskan and Canadian gas volumes as well as the dramatic increase in the price of Canadian gas" which will result in increased capacity and fuel savings benefits.

The entire Western Leg project as approved by the President in September 1977 would involve construction of 341 miles of 36 inch pipeline looping in the PGT system from Kingsgate to Malin, Oregon and some 143 miles of 36 inch pipeline looping on the PG & E system between Malin and Antioch. South of Antioch, up to 104 miles of 36 inch pipeline looping on the PG & E system would be required. Although this proposal was approved by the President, the project sponsors subsequently decided to use only 160 miles of 36 inch looping along the PGT system from Kingsgate to Stanfield, after which the Western Leg loop would deviate from the original proposal. Over objections of the Staff and the California PUC, the Commission in its 1/11/80 order approved construction of the first 160 miles of the Western Leg segment as proposed (and also decided it would issue separate decisions with respect to the remainder of the Western Leg and the Eastern Leg segments). (See Report No. 1244, pp1-5.)

In the instant order, the Commission noted that the determination of sizing and capacity of the ANGTS is within the exclusive jurisdiction of the Secretary of Energy; hence, it amended the 1/11/80 order to conform to his decision that the pipe size of the proposed loops on the Kingsgate to Stanfield pipeline should increase from 36 to 42 inches in diameter.

The Commission observed that the Secretary's determination generates the necessity, pursuant to the President's decision, that it make an additional finding as to whether the certification cost estimate for this pipeline segment materially and unreasonably exceeds the comparable capital cost estimates involved by the Alcan sponsors made on 3/8/77. In so doing, the Commission looked to the DOE Secretary's reasoning for approving the increase in pipe size. Among other things, he noted that the change in diameter would increase the pipe cross-section area by about 36% thus greatly increasing capacity and reducing fuel consumption per unit of gas transported. This, the Secretary noted, takes on special importance because of recently announced price increases for Canadian gas. At the same time, the estimated capital cost for a 42 inch system would increase only 27 to 30 percent -- which would be more than offset by the fuel savings. Based on the Secretary's reasoning, the Commission concluded that the increase in pipe size would not cause the capital cost estimates to materially and unreasonably exceed those filed on 3/8/77.

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On 1/23/80 Foothills Pipelines (Yukon) Ltd. issued a press release announcing that it will proceed with commitments which must be made to meet the 11/1/80 start-up date of the Western Leg prebuild facilities because "very little can be done to amend or change" the NEB export decision which resulted in a decrease of exports to Pan-Alberta for the ANGTS system from 4.9 to 1.8 Bcf. These commitments, Foothills noted, include purchase of materials and equipment, acquisition of land right of way and on-going project management in order to meet the target date. Meanwhile, Foothills noted Pan-Alberta intends to make applications to the NEB "to try to obtain more favorable terms to their present license."

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On 2/6/80 Northwest Alaskan Pipeline Co. (CP78-123) filed a notice of amendment to the partnership agreement relating to construction and operation of the Alaskan segment of the Alaska Natural Gas Transportation System. The amendment provides for expansion of the partnership ~~-- presently consisting of~~ included Northwest Alaskan Pipeline Co. as general partner, plus affiliates of Northern Natural Gas Co., Panhandle Eastern Pipeline Co., Pacific Gas and Electric Co., Pacific Interstate Transmission Co., and United Gas Pipeline Co., - to include American Natural Alaskan Co., a wholly owned subsidiary of American Natural Resources Co. 1/ American Natural is the parent of Michigan-Wisconsin Pipeline Co. which has contracted to purchase one-third of Exxon Corp.'s Prudhoe Bay production.

The Alaskan Northwest partnership was formed on 1/31/78. The partnership agreement included a "discount" provision intended to recognize that early participation of the original partners constituted a greater risk than participation commencing at a later date by any additional partner. Accordingly, the agreement specified that partners joining after 3/17/78 would be subject to a discount with respect to profits, losses and credits from their otherwise percentage share on the basis of ownership -- with such discount increasing the later the partner joined after 3/17/78. The discounts set forth in the agreement (as amended in May 1978) were 1% for partners admitted between 3/18/78 and 6/30/78, 2% for partners admitted betwen 7/1/78 and 12/31/78, 4% for those admitted between 1/1/79 and 6/30/79, 6% for those admitted between 7/1/79 and 12/31/79, 10% for those admitted between 1/1/80 and the commitment date, and 15% for those admitted after the commitment date. In a 6/30/78 order generally approving the terms of the partnership agreement, the FERC endorsed the discount principle as a means for giving effect to the varying degrees of risks assumed by the partners dependent on the date of membership, but requested further information to support the discount schedule and its relationship to the risks of participation and motivation of others to become partners. Pending receipt of such information, the Commission directed that the discount remain at 2%. (See REPORT NO. 1164, pp5-6.)

The instant amendment effectively provides for addition of American Natural Alaskan to ~~the partnership~~ without a discount. Specifically, for purposes of applying the discount provision, American Natural Alaskan will be deemed to have been a partner on or before 3/17/78. In addition, the present partners ~~have~~ agreed to waive any discount for a further period of thirty days (following FERC notice of the amendment) with respect to other qualified entities (excluding producers of North Slope gas) desiring to join the partnership. ~~This offer "exemplifies the partnership's continued commitment to broad participation in the project."~~

1/ The participation of American Natural in the Northwest Alaskan partnership was previously announced on 12/3/79.

After the thirty-day period, however, the partnership contended that continued relaxation of the discount terms ~~is~~ would no longer be justified in light of the financial commitments already made by the present partners. Specifically, the existing partners have spent over $118 million to date, have borne all the risks and have shouldered the entire burden of seeking to fulfill the multitude of regulatory requirements. In addition, the Commission has decided many of the most "vexing" problems facing ANGTS, including problems that probably deterred some companies from joining the partnership. Thus, "the point has been reached where a hopeful participant should not get a free ride by simply making up past payments."

Accordingly, the partnership proposed reinstitution of the discount schedule following the thirty-day period, thereby effecting a 10% discount until the commitment date when the discount will increase to 15%. In light of all the circumstances, the partnership contended that these 10% and 15% discount rates are "an accurate reflection of the risks and expenditures undertaken by the partnership to date, and provide an equitable balance between the recognition of those sacrifices and the maintenance of an opportunity for others to join the project at a time when the chance of failure has been reduced considerably."

House Select Committee on OCS Recommends Accelerated Five-year Leasing Program; Interior's Final Environment Statement Available

On 1/29/80 the House Select Committee on the Outer Continental Shelf released a staff study recommending, among other things, that 38 lease sales be scheduled over the five-year period ending February 1985, instead of 30 and 33 sales, respectively, as recommended by the Department of Interior and the Department of Energy. The report also emphasized that while implementation of the five-year plan as required by the Outer Continental Shelf Lands Act Amendments of 1978 has been "proceeding reasonably well," there have been delays "as exemplified by the jurisdictional conflict between DOI and DOE" regarding production goals, regulations for alternative bidding systems and due diligence.

At the outset, the Committee staff report noted that the Shelf Lands Act directs DOI to prepare, periodically revise and maintain a five-year OCS leasing program. On 3/9/79 DOI first announced a proposed leasing schedule which included twenty-six sales beginning March 1980, or an average of five per year. However, on 6/8/79 DOI revised the plan to increase the sale from 26 to 30, or an average of 6 per year between March 1980 and February 1985. In the meantime, DOE published a recommended leasing schedule -- acting under its authority to set production goals for OCS development pursuant to a Memorandum of Understanding with Interior -- calling for 33 sales. DOE's proposal would include three more sales on the Gulf of Mexico, but with virtually the same environmental and socioeconomic impacts as Interior's proposed schedule.

With respect to the jurisdictional differences between DOE and DOI, the Committee staff report stressed that the most obvious "manifestation of this inter-agency friction became evident during the development of the five-year leasing program, with DOI proposing five sales per year in their March draft schedule, and DOE advocating an average of seven sales per year." At this point, the report said, President Carter had to step in to direct DOI to accelerate the OCS leasing program. Further, the report continued, the split authority was resulting in substantial delays in implementing all regulations covering OCS responsibilities transfered to DOE, including the use of production goals. Among other things, the Committee staff noted, DOI did not use production goals developed by DOE in estimating its March 1979 leasing schedule. Meanwhile, the Leasing Liaison Committee established by the Act as a coordination mechanism had "been grossly ineffective in resolving any inter-agency problems that had arisen."

Concerning issuance of regulations for alternative bidding systems, the report noted that DOE sent DOI proposed new regulations on most of the bidding systems on 9/28/78, after DOI earlier rejected DOE's draft regulations on four of them. "The potential seriousness of such jurisdictional conflicts and attendent delays in the promulgations for the use of alternative bidding systems was exemplified in June 1979 when citizen groups cited the lack of alternative bidding regulations as a basis for challenging the OSC leasing program." When DOE finally decided to publish its proposed regulations for alternative bidding systems, DOI requested the Office of Management and Budget to intervene.

Finally, while DOE has responsibility for issuing "due diligence" regulations, DOI issued proposed regulations on 1/17/79 which would require submission of exploration plans within two years of awarding a lease in all OSC areas. "Although DOE clearly has the authority to issue diligence regulations, Interior has asserted its interests in the prompt and efficient exploration or development of OSC leases, particularly until and pursuant to any action taken by DOE on the matter."

The Committee staff suggested that OSC development can be accelerated by timely appropriate action to (1) remedy budgetary constraints; (2) facilitate inter-agency coordination; (3) accelerate environmental studies in frontier areas; (4) provide contingency sales; (5) accelerate leasing.

With regard to the budget, the staff noted that insufficient administrative resources have delayed implementation of the Shelf Land Act and hindered accelerated exploration and development of the OCS. "It is therefore incumbent on both the Congress and the Administration to provide needed funding if a truly effective OSC leasing program is desired."

With regard to the agencies, "better coordination between all the departments is clearly needed. Moreover, DOE must proceed to issue final regulations on the alternative bidding system, due diligence requirements, competition measures and in-kind royalty oil collection and distribution, with January 1, 1981 as the target date for final issuance."

As for the environment, the staff found a need for further studies, especially in the proposed frontier areas where additional lease sales should be scheduled. Also there should be at least two more contingency sales to compensate for sales held up because of litigation, or because new or additional information suggests that a particular sale should not go forward as planned.

The staff further recommended that DOI study and adopt, where appropriate, the proposed second phase constituent sale mechanism whereby tracts not leased in the first phase of a lease sale could be offered again after one year, particularly for frontier lease sales.

Finally, the Committee staff recommended the following changes in DOI's proposed five-year lease schedule: (1) add five Gulf of Mexico sales beginning in June 1980; (2) drop the Gulf of Alaska sale in 1980; (3) add a Beaufort sale in 1982; (4) add a Navarian Basin sale in 1982; (5) add a Zhemchug-St. George sale in 1983; (6) add a Mid-Atlantic sale in 1984; and (7) move the Norton Basin sale from 1982 to November 1981. This would provide a total of 38 sales over the 1980-1985 period -- 4 in 1980, 8 annually from 1981 to 1984 and 2 in 1985.

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On 1/21/80 DOI announced the availability of a final environmental statement relating to the proposed five-year OCS oil and gas lease sale schedule. At the outset, DOI explained that 30 oil and gas lease sales (Alternative 1) are anticipated in the North Atlantic; Mid-Atlantic; South Atlantic, including Blake Plateau; Southern California, including Santa Barbara Channel; Gulf of Alaska; Cook Inlet and the Beaufort Sea -- all areas where previous oil and gas lease sales have been held or are proposed to be held prior to March 1980. Sales are also considered in Central and Northern California; Kodiak; Northern Aleutian Shelf; St. George Basin; Navarin Basin; Norton Basin; and Chukchi Sea -- all areas where no previous OCS oil and gas lease sales have been held, or in the case of Central and Northern California, no recent sales has been held, and no development has taken place.

Alternative 1 would result in offering about 32 million acres for leasing during the five-year period under consideration. The estimated mean resources resulting from this schedule are approximately 6.6 billion barrels of oil and 29 Tcf of gas.

The FES considered nine other alternatives -- three primarily involving sale delays within the five-year timeframe; three primarily involving omissions of sales from the schedule; two involving a slower pace of leasing; one involving 33 sales in 13 leasing areas; and one other involving no-action and conservation.

More specifically, Alternative 2 would involve 33 sales in the five-year period, omitting consideration of sales in Navarin Basin and Northern Aleutian Shelf, and decreasing by one the sales in offshore California by not considering a second sale in central and northern California. This alternative schedule includes more sales than Alternative 1 by 14 Gulf of Mexico sales (an additional three) and two sales each in the Gulf of Alaska, Beaufort Sea and St. George Basin. Alternative 3 involves a delay in sales for Norton Basin, St. George Basin and Northern Aleutian Shelf from dates proposed in Alternative 1 (September 1982; December 1982; and October 1983, respectively), in order to allow unorganized boroughs to undertake local coastal zone management planning. Alternative 4 would hold the proposed St. George Basin sale in 1983 (Alternative 1 schedules this sale in 1982) to allow additional time for further environmental data collection. Alternative 5 would hold the proposed Central and Northern California sale in 1983 (Alternative 1 scheduled this sale in 1981) to allow time for further environmental data collection. Also, the 1983 California sale included in Alternative 1 would be omitted and the 1984 California sale would be designated as a Southern California sale. Alternative 6 would omit Northern Aleutian Shelf from consideration for leasing in the five-year schedule, to allow additional time for long-term environmental data collection and environmental impact analysis. Alternative 7 would omit the Chukchi Sea from consideration for leasing in the five-year schedule, and substitute a Beaufort Sea sale in the schedule in 1985, in order to develop technology for shear zone and pack ice conditions in an area of existing infrastructure and transportation network. Alternative 8 would schedule 25 OCS lease sales, omitting Northern Aleutian Shelf, St. George Basin, Navarin Basin, Norton and Chukchi Sea from consideration for leasing in the five-year schedule, to reduce the amount of Alaskan oil and gas for which transportation will need to be developed and processing logistics resolved or facilities developed. Alternative 9 would schedule 28 OCS lease sales, omitting Northern Aleutian Shelf, St. George Basin and Chukchi Sea; add Hope Basin; and hold Kodiak and Norton Basin later than proposed in Alternative 1. Also, the Beaufort Sea sale would be confined to the landfast ice zone. Alternative 10 is a no-action and conservation alternative.

At the outset, the FES noted that the environmental concerns raised most often involved marine resources and subsistence resources and lifestyle in Alaska; sensitive marine mammals and seabirds in Central and Northern California; air quality and recreation in California; the possible environmental effect of Arctic development due to the lack of existing technology to develop that area and possible consequences of oil spills in sea ice conditions; and cumulative impacts to endangered whale species, especially in the Pacific.

A major environmental impact producing factor inherent in the production of OCS oil and gas is oil spill risk, the FES said. Based on volume of oil estimated and historical experience, in excess of 33 oil spills greater than 1,000 barrels are statistically probable as a result of development stemming from sales included in Alternatives 1, 3 and 4. A similar amount of total spills would result from Alternatives 5, 6 and 7. However, these alternatives would result in reduced risk of spills to specific regions. Alternative 2 would result in a similar number of total spills being probable, but the distribution would vary. Alternatives 8 and 9 would result in significantly less spills being probable, which would reduce spill likelihood in Alaska.

All OCS leasing areas were judged to be at least moderately sensitive to oil spill impact to fisheries resources and the North Atlantic highly sensitive due to endemic stocks; however, the Gulf of Alaska, Kodiak, Northern Aleutian Shelf and Norton Basin have a markedly smaller risk of oil spills than other regions, due to relatively low projected amounts of oil. Based on the presence of species which have been identified as being of concern relative to OCS development, the North and Mid-Atlantic Southern California and all Alaska areas are judged to be relatively high sensitivity areas for endangered species. Central and Northern California, and all Alaska areas except Cook Inlet and Navarin Basin, are considered most sensitive to marine mammals due to the abundance of breeding populations.

In addition to large oil spills development activities as a result of leases issued during the five-year schedule of OCS oil and gas leases "will cause chronic oil pollution through routine discharges and accidental spillage; the release of toxic chemicals in drilling muds and formation waters; smothering effects of drill cuttings; and sedimentation and smothering due to pipeline burial. By and large, these impacts will occur in localized areas around drilling platforms and pipelines."

The FES stressed that the level of these impacts cannot be assessed in any quantitative manner at this time. The lack of specific tract locations makes even qualitative analysis of impacts difficult, as proximity to resources of concern and oil spill trajectories cannot be determined at the program level of planning. Multiple use conflicts are also difficult to assess, the FES continued, in the absence of specific sale proposals.

The FES further concluded that the placement of structures on the OCS can also contribute to navigational conflicts, resulting in a higher potential for accidents, including those involving oil, LNG and hydrocarbon product tankers; impacts to local and regional economies, infrastructure, and land use are expected to be generally low to moderate; and in Alaska, major commitments of land to new industrial uses and large influxes of workers, relative to the existing population, can be expected. Based on experience in the North Slope development, and in response to anticipated local and state desires and pressures, it is anticipated that facility development will be isolated from any nearby communities and interaction restricted through the establishment of enclaves. This should reduce potential impacts to infrastructure and social impacts to subsistence communities.

Development activities stemming from Alternative 1, the FES concluded, will result in increased conflicts with other uses of the OCS and the coastal zone. These range from minor inconveniences to local, severe short-term use curtailments from oil spills, including those resulting from tanker collisions. "Loss of lives from tanker collisions and other accidents may also result. The extent of these impacts will be largely determined by specific tract selections made at the sale decision stages, and can be mitigated to some degree through tract selection decisions and stipulations imposed in the sale decision, and by regulation in the post-sale stage."

Impacts resulting from Alternatives 3, 4 and 5, involving delay of sales within the five-year schedule, are expected to be the same as, or very similar to Alternative 1. Impacts resulting from Alternative 6, omission of the Northern Aleutian Shelf from consideration in the five-year schedule, would be the same except in the Bering Sea region. There, the potential for oil-related individual mortality or population reductions to breeding sea ducks, to migrating marine mammals and fish, to breeding populations of seals and to the other components of the area's marine and coastal ecosystem would be reduced.

The overall level of impact from Alternatives 2 and 7 would be similar to those of Alternative 1, based on the similar level of facilities required and probable spills. However, the focus of impacts would differ. Both may somewhat reduce various onshore impacts in Alaska, including those to Native subsistence resources and lifestyles, as fewer areas would be developed.

Alternative 8, involving only 25 sales (none in the Bering Sea region or the Chukchi Sea) would result in elimination of all impacts in the Bering Sea and much reduced impacts in the Arctic region. Alternative 9, involving only 28 sales, would reduce impacts to the Bering Sea region (no sales would be held in the southern Bering), and would eliminate impacts in the Chukchi lease area, although it would add impacts to the southern Chukchi Sea -- i.e., Hope Basin. Alternative 10 (no action and conservation) would eliminate the impacts resulting from the new OCS development. However, the FES added, if energy supplies anticipated from the proposal were replaced with imported hydrocarbons or increased development of alternate energy forms, other environmental effects would result. Increased importation, should it occur, could pose greater risks of tanker accidents and major spills in coastal areas. Development of energy from coal or shale would increase the risk of greater air and water pollution for interior portions of the country. If no action is taken to continue OCS development and energy shortfalls result, the primary impacts would be economic.