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HIGHLIGHTS

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Congressman Udall Introduces New Version of Energy Mobilization Board Legislation

On 10/22/79 Rep. Morris K. Udall (D-Ariz.) introduced H.R. 5660, a new version of legislation to create the President's proposed Energy Mobilization Board and put the licensing of important energy projects on a "fast track." H.R. 5660 differs in various respects from H.R. 4985 and H.R. 4862, bills recently reported out by the House Interior Committee (chaired by Rep. Udall) and the House Commerce Committee, respectively. The House bills, in turn, differ from S. 1308, the Senate's bill to create an EMB which was passed on 10/4/79.

A proposal for an EMB was included in new energy proposals announced on 7/16/79 by President Carter designed to reduce oil imports by 4.5 million b/d by 1990. The President's proposal was subsequently introduced in the Senate by Senator Henry Jackson (D-Wash.), Chairman of the Senate Energy Committee. As passed by the Senate on 10/4/79, S. 1308 would create an Energy Mobilization Board to establish priorities for energy projects which are in the national interest, including reasonable deadlines which would be binding on all federal, state and local agencies. If any federal, state or local agency failed to make a decision or take an action within the time required, the EMB could make the decision or perform the action in lieu of the agency. The Senate rejected an alternative which would have excluded certain of this authority over state and local governments.

On the House side, the Interior Committee approved H.R. 4985 on 7/26/79, establishing an EMB which could not waive state or local law, although the President could waive time requirements for federal agency action, and governors could waive state and local time rules. Subsequently, on 9/12/79, the Commerce Committee approved H.R. 4862, under which the Board could recommend waiver of federal, state and local statutes to the President who, in turn, could forward the final decision to Congress. This decision would be subject to a one-House veto. (See REPORT NOS. 1218, pp1-2; 1227, pp17-18; 1230, pp1-7.)

On 10/25/79 the House Rules Committee decided that the versions reported by the House Interior and House Commerce Committees would both be considered on the floor, together with any amendments which are printed in the Congressional Record by 10/29/79. This would include Rep. Udall's version (H.R. 5660), which was introduced on 10/19/79 as a separate bill and as an amendment in the nature of a substitute to H.R. 4985. In so doing, Rep. Udall emphasized that his proposal "moves closer to the outlines of the President's proposal than did the version reported by the Interior Committee . . . . It is the product of discussion with members, the governors and local officials, industry and environmental groups. While it does not bear the stamp of formal Committee approval, it enjoys the informal support of a wide range of political philosophy on the Committee."

Specifically, H.R. 5660 would create a five-member EMB to promuglate regulations establishing procedures and criteria for the submission of applications for an order designating an energy project as a Priority Energy Project. The application must include detailed information to permit the Board to make a designation as a Priority Energy Project; identify each agency required to make a decision with respect to such project; and determine the agency decisions which must be made with respect thereto. Further, the application must include a design proposal for the project; economic data on costs and benefits thereof; energy to be produced or conserved thereby; and an analysis of the social health and safety and environmental impacts of the project, including mitigating measures.

Promptly following receipt of such an application, the Board must publish a notice thereof in the Federal Register and notify appropriate federal, state and local

agencies, the governors of affected states, the Senate Energy and House Interior and Commerce Committees, and "other interested parties." Written comments may be submitted within 45 days of the notice.

Within 45 days after expiration of the comment period, the Board must either approve or reject the application for an order designating the energy project as a Priority Energy Project. In making this determination, the EMB must consider (1) the extent to which the project would reduce the nation's dependence on imported oil or other nonrenewable resources; (2) the magnitude of any economic and social impacts and costs associated therewith in relation to alternatives; (3) the extent to which the project would make use of renewable energy resources or conserve energy and contribute to development of new production or conservation technologies; (4) the time normally required to obtain all necessary agency decisions; (5) adverse impacts; (6) the extent to which the project would impinge on presently available (or future) water resources; (7) the comments received concerning the project; (8) regions of the country that will be most heavily impacted or benefitted by the project; (9) the availability of significant economic, environmental or technical data; (10) the anticipated effects upon competition and the energy industry; (11) the magnitude of any adverse environmental impacts; and (12) the cost effectiveness and energy efficiency of the project.

Regulations under this section must be submitted to both Houses of Congress and will take effect after 60 days unless vetoed by either House. Also, not more than 75 Priority Energy Projects may be designated by the Board and not more than 20 thereof may be designated in any one calendar year.

After designation of any Priority Energy Project, the EMB must promptly notify the governor of each state and each Indian Tribe in which any portion of the project will be located and they may appoint a nonvoting member to the Board to participate in decisions respecting the project, including decisions relating to the Project Decision Schedule described below.

Also, within 45 days after a Priority Energy Project is designated, each agency having authority to make any decisions with respect thereto must transmit to the EMB (1) a compilation of all significant actions which the agency and the applicant must take before a decision can be made (and a summary of legal procedural requirements); (2) a tentative schedule for completing such actions and making such decisions; and (3) the amount of funds and personnel available to the agency for these purposes (and the effect thereof on other required agency actions).

Upon receiving this information, the EMB must seek mutual agreement with the affected agencies and applicants on a practical and expedited Project Decision Schedule, which then must be published within 45 days. The Project Decision Schedule must clearly identify the order in which decisions are to be made by each agency concerning the project and clearly identify the deadlines applicable to such decisions. The Project Decision Schedule may also recommend concurrent review of applications and joint hearings by state and local agencies. Whenever the schedule is inconsistent with any other schedule that would otherwise apply, it will apply in lieu of the latter and must be binding on the agency and all other persons to which the schedule applies. The Project Decision Schedule must "be reasonably designed to ensure complete consideration of all matters concerning such project under applicable law and to ensure adequate participation by interested parties in applicable proceedings." The bill contains provisions permitting modification of the Project Decision Schedule upon petition of any agency under certain conditions.

The EMB must monitor compliance with the Project Decision Schedule by agencies and persons to whom it applies and require them to submit information regarding compliance. "If the Board determines that a Priority Energy Project is being delayed or threatened with delay, the Board shall determine the reason for such delay or threatened delay and notify the appropriate agencies and other persons of its determination."

Except as otherwise provided in the bill, the Project Decision Schedule and each agency decision and other actions with respect to deadlines or timetables must be consistent "with the statutory obligations applicable to the agencies governed by such schedule."

If any agency fails (or is likely to fail) to comply with a Project Decision Schedule, the EMB may bring an expedited enforcement action in the appropriate U.S. District Court. If any federal, state or local agency then fails to make a decision or take an action pursuant to a court order, the President may perform the action or make the decision in lieu of the agency.

The EMB's authority will expire seven years after the date of enactment.

H.R. 4985 (the House Interior Committee version) would also establish a five-member EMB to promulgate regulations establishing criteria for applications for an order designating an energy project as a Priority Energy Project. Such application must "include such detailed information as the Board deems necessary to enable it to make such a designation . . ., to identify each agency required to make an agency decision with respect to such project, and to enable such agencies to determine the agency decisions which they are required to make with respect to such projects."

Within 30 days after the application, the Board must publish a notice thereof in the Federal Register and provide 45 days for written comment. Within 45 days thereafter, the Board must decide whether the energy project will be designated as a Priority Energy Project. In making this decision, the Board must consider similar type information as required in Rep. Udall's version described above.

H.R. 4985 provides that no more than 24 Priority Energy Projects may be pending certification at any one time, and no more than 12 may be designated in any one calendar year.

Like H.R. 5660, this bill would also direct each agency having authority to make a decision with respect to a designated Priority Energy Project to submit a compilation of all significant actions required by the agency and the applicant before a decision can be made (and a summary of legal procedural requirements), a tentative schedule for completing such actions, and a statement of the amount of funds and personnel available to the agency to take such action.

Within 60 days after the above information is submitted, H.R. 4985 directs the EMB, in consultation with appropriate agencies, to publish a Project Decision Schedule for all agency decisions relating to the project. The schedule must clearly identify the order in which the decisions must be obtained to carry out the Priority Energy Project, and may also recommend concurrent review of applications and joint hearings by the agencies and instrumentalities. "Whenever such Project Decision Schedule is not consistent with the schedule which would apply under otherwise applicable rules and regulations, such Project Decision Schedule shall apply in lieu of such otherwise applicable schedule and shall be reasonably designed to ensure adequate consideration of all matters concerning such project

under applicable law and to ensure adequate participation by parties in applicable proceedings." Moreover, the schedule must "be consistent with the statutory obligation of the agencies governed by such schedule," and the designation as a Priority Energy Project "shall not be construed to affect the application to such project of any requirement established by, or pursuant to, federal, state or local law; the basis on which any agency decision is made with respect to such project; and the outcome of any such decision."

Also, no deadline (or extension thereof) may result in the total time for federal, state or local agency action exceeding nine months from the time the notice appears of an order designating the Priority Energy Project.

The EMB must monitor compliance with the Project Decision Schedule. If the Board determines that a Priority Energy Project is being delayed or threatened with delay, it must determine the reason and notify the appropriate agencies and other persons of its determination. With respect to federal agencies, the Board "may establish such procedures as it deems appropriate to bring such agency into compliance with the Project Decision Schedule." If a deadline for a final decision or action by a federal agency has elapsed, the President must make the decision or perform the action within 60 days in lieu of the federal agency. The President may also grant a 120-day extension of the time for federal agency action.

H.R. 4985 also permits an agency to make a negative determination within its authority, in which case the Priority Energy Project will be terminated.

The bill includes provisions for state cooperation. Specifically, the EMB must notify the governor of any state where a Priority Energy Project would be located and request him to supply (1) a compilation of significant actions required by the state and local governments and the applicant before the project can be completed; (2) a schedule for completing such actions; and (3) all necessary application forms which the applicant must complete. After consultation with state and local authorities, the EMB must propose a decision schedule to assist state and local authorities in coordinating their activities with the Federal Government. The Board may participate or intervene in the proceeding of any state or local agency (which permits such participation or intervention) in order to request the agency to adopt the Board's recommended procedures. If the Board determines that a project is being delayed or threatened with delay by the inability or unwillingness of any state or local government to implement a schedule for timely review and decision, it must notify the governor and transmit to Congress a statement describing the delay and recommend action to alleivate it.

Furthermore, whenever the Board determines, after consultation with the affected agencies, that any federal, state or local time requirement for agency action is unreasonable and presents a substantial impediment to the agency decision specified in the Project Decision Schedule, the Board may recommend to the President (with respect to federal agencies) or chief executive officer of the state involved (with respect to state and local agencies) that the time requirement be waived in whole or in part. Within 30 days, the President may submit such recommendation to Congress, which will take effect after 30 days unless vetoed by either House.

The Board's authority would expire seven years after the date of enactment.

H.R. 4985 (the House Commerce Committee version) would also establish a five-member Energy Mobilization Board to promulgate regulations establishing procedures and criteria for applications for an order designating an energy project as a Priority Energy Project. The application must include information generally

similar to the information which must be provided under both H.R. 5660 and H.R. 4862 described above. Also, H.R. 4985 and H.R. 4862 are similar with respect to publishing the notice of the application, providing for written comments, designation of the Priority Energy Project, extension of deadlines, transmission of information by the states and establishment of a Project Decision Schedule.

With respect to monitoring compliance with a Project Decision Schedule, H.R. 4985 would permit the EMB -- if it determines that a Priority Energy Project is being delayed or threatened with delay -- to "take such actions as it deems appropriate to bring such agency and other persons into compliance with the Project Decision Schedule."

H.R. 4985 further provides that if the EMB determines, after consultation with the agencies concerned, that any federal, state or local requirement presents a substantial procedural or substantive impediment to the making of any agency decision in a manner which will permit implementation of a Priority Energy Project according to the schedule, the Board may recommend to the President that such requirement be waived in whole or in part. The EMB may also review any federal, state or local requirement promulgated after establishment of the schedule to determine if it presents similar impediments to implementation of the project and may then recommend to the President that the requirement be waived in whole or in part. If the President determines such a waiver to be in the national interest, he may transmit this determination to Congress which will then be subject to one-House veto.

The EMB would terminate on 9/30/85.

Differences between H.R. 4962 and H.R. 5660 were described in a statement released by Rep. Udall. He explained that unlike the Commerce Committee bill, H.R. 5660 does not grant the EMB authority to recommend the waiver of substantive local, state and federal laws, although it does give the Board the power to set deadlines and to temporarily suspend new laws. Also, it would delegate to the President the power to decide cases where state or local governments have not acted. "But in every case of enforcement, the government will be following the law. Under the Commerce version, the law would be waived . . . . The Commerce bill is an unbridled assult on the fundamental American notion that the direction of the economic and industrial future of a city or state is best decided by the people and governments of those states. Certainly, there has been necessary incursion into this principle and the presence of federal policy is strongly felt in all regions. But we should not go so far to impose wholesale federal power to wipe out opportunities for local governments to decide how their communities will develop."

GAO Report Recommends Establishment of Energy Mobilization Board for Expediting Review of Priority Energy Projects

On 10/15/79 the General Accounting Office (GAO) released a report recommending the establishment by Congress of an Energy Mobilization Board to provide for expedited consideration of priority energy projects. The report based its recommendations in part on an analysis of the circumstances surrounding the cancellation of plans by the Standard Oil Co. of Ohio (Sohio) to construct a major west-to-east crude oil pipeline to carry surplus Alaskan North Slope crude oil from Long Beach, California to Midland, Texas. The PACTEX project was treated as a case study of problems associated with federal, state and local approvals of priority energy projects by the report.

In analyzing the PACTEX project, the GAO found that the greatest amount of delay resulted from attempts to obtain the appropriate state and local air quality permits for the California terminal. The report also noted that the Environmental Protection Agency's failure to set clear and definitive requirements on its new-source offset policy contributed to controversies surrounding the grant of appropriate air quality permits. Under the new-source offset policy, industry growth would be permitted in a nonattainment area provided its emissions were offset by emission reductions from existing installations. This policy was adopted in response to concerns that the Clean Air Act Amendments of 1970, in establishing nonattainment areas where no further industrial activity could occur, would cause a complete suspension of industry growth, thereby creating economic and social hardships. The report noted that specific problems with regard to the offset policy developed because EPA provided no guidelines on how a new source review was to be conducted. Given the lack of such guidelines, PACTEX officials were forced to engage in lengthy negotiations with the California Air Resources Board regarding how such offsets should be provided, how they should be measured, what actual amounts of emissions needed to be offset, and whether a demonstration project using an unproven technology would be acceptable. The report also stated that litigation related to the offset policy further delayed the project. The delays, according to GAO, resulted from the fact "there were very few or no precedents on which to base most decisions . . . the guidelines were developed as the project proceeded." This lack of appropriate direction was exacerbated by the lack of an appropriate single agency which would have jurisdiction to require that federal, state and local agencies make decisions in advance in order to provide guidance to all parties concerned.

The procedures in existence for expediting priority projects at the time of consideration of the PACTEX were not viewed as adequate by the GAO report. Specifically, the report noted that Title V of PURPA, which sets forth expedited procedures for decisions on west-to-east crude oil pipelines, did not contain any provisions related to state or local law or litigation. The special treatment outlined in PURPA thus provided no assistance to PACTEX in California, the report said.

On the basis of the PACTEX experience, the report found valid reason for establishment of a program administered by a single agency with appropriate jurisdictional powers to expedite priority energy projects. The report noted that the existence of such a program would eliminate the need for Congressional action on separate projects, avoid duplicative judicial review, and provide standardized, equitable procedures for all priority projects.

To administer such a program, GAO recommended the establishment of an Energy Mobilization Board which would be reasonably independent, representative of various interests, and invested with sufficient authority to designate priority projects, set procedural deadlines and enforce permitting schedules. The report further recommended that the Board be given the power to override disapproval of a given project by any government entity. Legislation to establish such authority should, however, be carefully drawn in order to prevent possible abuses. As an example, the GAO report suggested that the legislation clearly specify the types of laws which the Board must consider in arriving at any decision to override. The report also recommended that such legislation specify limitations with regard to judicial review. A sunset provision should also be incorporated, the report concluded.

ERA Considers Program to Provide Electric Powerplants with Additional Natural Gas to Induce Increased Coal and Other Nonpetroleum Fuel Usage and Production of Heavy Oil

On 10/18/79 the ERA issued a notice of inquiry (ERA-R-79-49) with rspect to "several possible changes to the existing federal system of gas regulation which may provide incentives for the conversion of existing facilities to coal and other nonpetroleum fuels, the building of new coal and other nonpetroleum fuel capable facilities, and the increased production of heavy oil." The ERA requested comments by 12/31/79 on two alternative mechanisms to achieve such goals: (1) the adoption by ERA of a natural gas curtailment priority rule whereunder eligible electric powerplants would receive high priority status in the curtailment plans of interstate pipelines if they agree to convert to coal within a reasonable time, such as five years; and (2) a proposal by ERA that the FERC adopt a direct purchase transportation rule to facilitate transportation by interstate pipelines of gas owned by powerplants which are scheduled to burn coal or a nonpetroleum fuel at some specified date. 1/

At the outset, the ERA noted that a major purpose of the Powerplant and Industrial Fuel Use Act is to encourage the greater use of coal and other nonpetroleum fuels in lieu of natural gas and petroleum as a primary energy source. Also, the President favors a program to encourage greater use of coal and to make natural gas available for the production of heavy oils.

The ERA referred to several recent suggestions to achieve these goals. First, the ERA said, the FERC -- in its 6/28/79 notice of inquiry (RM79-56) inviting comments on a proposal to link incremental pricing and curtailment policies -- suggested that the ERA could provide electric powerplants high priority status in the curtailment plans of interstate pipelines to facilitate conversion to coal. 2/ Traditionally, the ERA stated, powerplants have been the first to be curtailed in a natural gas shortage and many, because they have been continuously curtailed, have had to develop other more costly sources of supply. The FERC suggested that priority access to cheaper natural gas pipeline system supplies might represent both an incentive and, since it is cheaper, a means for acquiring new coal burning equipment or converting existing equipment to coal or other nonpetroleum fuels. Others have suggested that priority access to natural gas may also result in increased coal use by facilitating the opportunity for powerplants to obtain a mixture exemption under FUA. 3/ For example, use of gas along with coal in order

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1/ Section 403 of the DOE Organization Act permits the ERA to propose rules to the FERC for its consideration and adoption.

2/ Specifically, in discussing what categories of users, in addition to large industrial boiler fuel users, could be made subject to the FERC's proposal, the Commission noted that electric utility boiler users are excluded by the NGPA from incremental pricing, so that it is not clear whether the Commission's proposal could be applied to such uses. "Assuming that electric utility boiler fuel users are prime targets for coal conversion under the Fuel Use Act, it may make the most sense to give electric utilities high priority access to natural gas if they are either subject to a coal conversion order or have voluntarily provided sufficient evidence that they will convert to coal within a reasonable period of time, perhaps five years. This would give electric boiler fuel users the benefit of rolled-in pricing as a means and an incentive for acquiring coal burning equipment."

3/ Specifically, under the FUA mixture exemption, powerplants may be granted authorization by the ERA to burn natural gas and coal or another nonpetroleum fuel either in combination or on an intermittent basis.

to meet required environmental standards would result in more total coal usage in clean air nonattainment areas than would be possible with the use of coal alone. In addition, the use of gas in combination with synthetic fuels under the FUA mixture or synthetic fuel exemptions may facilitate the development of synthetic fuels, such as synthetic natural gas produced from coal, by offsetting the costs of such development.

The ERA also noted its concern that because of environmental problems, it may not be possible to continue large-scale use of petroleum fuels to recover highly viscous crude oil, primarily in California. Hence, ERA is exploring whether the federal curtailment priority system or other natural gas authority may be used to facilitate the use of natural gas to increase heavy oil production.

The ERA set forth for comment two specific proposals -- one involving the natural gas curtailment priority rule issued by ERA, and the second involving a direct purchase transportation rule to be issued by the FERC.

More specifically, the ERA explained, it could propose a rule directing that interstate pipelines may not curtail deliveries to designated electric utilities or heavy oil producers unless necessary to meet the needs of essential industrial process and feedstock uses, essential agricultural uses and high priority users protected under the NGPA and ERA regulations. Any electric powerplant -- which has received a temporary FUA exemption allowing it to burn gas while converting to coal or alternate fuel use, received a permanent FUA exemption to burn a mixture of gas and coal or gas and some other nonpetroleum fuel (including a synthetic fuel), received a proposed or final FUA prohibition order, or indicated the intent to voluntarily convert within a reasonable time (and provided sufficient evidence thereof), or received a delayed compliance order under the Clean Air Act -- would be placed in a curtailment plan priority just below essential industrial process and feedstock uses if, in compliance with the FUA exemption or a proposed or final prohibition order, it has filed a plan complying with terms and conditions set by the Secretary of Energy for increasing coal or other alternate fuel usage (including synthetic fuel), converting to coal or another fuel (including a synthetic fuel) or building new coal or alternative fuel burning facilities.

This priority would automatically terminate on the date that the powerplant's ERA-approved compliance plan commits it to go exclusively to coal or other alternate fuel use. Other powerplants would be placed in the same priority if they could certify that a specified amount of gas, when used in combination with another fuel for environmental purposes, would permit them to build new coal burning facilities or otherwise increase their coal usage. Users of natural gas for heavy oil production through thermal recovery methods would be placed in the same priority with the designated coal users.

Implementation of this priority rule could be either on a generic basis or a case-by-case approach. In the latter situation, the priority would only be given once the FERC had determined that a specific powerplant had filed the required compliance plans with DOE and was committed to phasing in an alternate fuel use. A priority would be given to specific heavy oil production sites when the determination was made that production by other methods was impractical.

Under the second option, the ERA would propose that the FERC adopt a rule facilitating the granting of Section 7 transportation certificates to interstate pipelines permitting the transportation of user-owned gas to the powerplants temporarily allowed to burn gas under a FUA exemption or prohibition order. This would permit the use of gas until existing facilities have been converted to coal or

other nonpetroleum fuels (including synthetic fuels) as specified by terms and conditions approved by the DOE Secretary; use of gas in existing facilities until a new coal burning or alternate fuel facility is in place; or use of gas on an intermittent basis in a new coal burning facility to allow it to operate during temporary periods when clean air standards are being violated. Also, the direct purchase rule could permit the transportation of any gas or be limited only to the first sale of high cost gas as defined by the FERC under the NGPA, or could allow the FERC to condition the transportation approval to ensure that high priority users will be served.

Further, the rule could facilitate the interstate transportation of user-owned gas to oil producers who require the gas for heavy oil recovery, where the gas will serve to initiate or increase heavy oil production.

The ERA requested specific comments on, among other things, whether (1) changes in the curtailment priority system would provide an incentive or disincentive for both conversion of existing facilities to coal and building of new coal or alternate fuel burning facilities; (2) assignment of a priority to electric powerplants should be done on a generic or case-by-case basis; (3) one of the two options would induce greater coal usage than the other; (4) the costs to be incurred would be measureably greater than the benefits to be obtained under such a program; (5) any changes would increase coal usage and mitigate against potentially harmful effects on other gas users; (6) other major fuel burning installations should be included; (7) curtailment priority should be given at the end user level to those electric powerplants who will convert to, or increase their useage of, coal or other nonpetroleum fuels in light of direct state control over who receives natural gas; and (8)natural gas supplies for the next decade will be sufficient to warrant allowing powerplants access to natural gas under either of the proposed options.

Six Companies Sign Contract for Purchase of Mexican Gas Imports

On 10/18/79 Border Gas, Inc., a consortium of six major U.S. natural gas companies, signed a contract to purchase natural gas from Mexico. The contract provides for the sale of 300 MMcf/d of natural gas at an initial rate of $3.625/Mcf. No details were given regarding price escalators, although officials of the Mexican state-owned oil company (PEMEX) stated that the escalators will be based on a composite of various crude oils.

Negotiations for sales began shortly after the 9/21/79 U.S. announcement of an agreement with Mexican Government on imports. That agreement specified the $3.625 per Mcf rate but left the issue of quarterly price adjustments open for negotiations.

The six companies and their respective percentages of ownership interest in Border Gas, Inc. are: Tenneco, Inc. (37.5%), Texas Eastern Corp. (27.5%), El Paso Co. (15%), Transco Cos. (10%), Southern Natural Gas Co. (6-2/3%), and Continental Resources Co. (3-1/3%). 1/ In August of 1977, the same six companies filed an application with the then FPC to import up to 2 Bcf/d of Mexican gas at a rate of $2.60/Mcf. That price, which was tied to the price of No. 2 fuel oil, was determined to be too high by the Administration, and the Memorandum of Intentions underlying the application subsequently expired on 12/31/77 after attempts to negotiate an alternate price failed.

No date has yet been set for commencement of deliveries although U.S. and Mexican officials previously expressed hope that a 1/1/80 startup date might be achieved. The Border Gas, Inc. group plans deliveries as soon as necessary government approvals are obtained.

1/ Continental Resources Co. is the successor to Florida Gas Co. through a merger with the Continental Group, Inc. in August 1979.

Northern and Columbia Gas Seek to Import Additional Long-Term Gas Supplies from Canada

On 10/11 and 10/24/79, respectively, applications were filed in the ERA by (1) Northern Natural Gas Co. (79-24-NG), to import up to 200,000 Mcf/d (73 Bcf per year) -- and daily volumes in excess thereof if available on a best-efforts basis -- from 11/1/80 through 10/31/94; and (2) Columbia Gas Transmission Corp. (78-30-NG), to import 41,000 Mcf/d (13.6 Bcf per year) for a period of 15 years. Both companies will purchase the gas at the applicable border price set by the NEB (which was $2.80/MMBtu at the time the applications were filed).

Northern will purchase its gas from Consolidated Natural Gas Ltd., and it will be delivered by TransCanada PipeLines Ltd. to Great Lakes Gas Transmission Co. at an existing point of interconnection on the international boundary near Emerson, Manitoba. 1/ Great Lakes will transport and redeliver the gas to Northern at a point of interconnection between their systems near Carlton, Minnesota and/or at points of interconnection between the facilities of Great Lakes and Michigan Wisconsin Pipe Line Co. near Fortune Lake, Michigan and Farwell, Michigan. Alternate delivery points will be at the point of interconnection of the facilities of Great Lakes and Northern near Grand Rapids, Minnesota and Wakefield, Michigan. Great Lakes will transport Northern's gas through existing facilities.

Consolidated will sell and deliver the 200,000 Mcf/d for Northern's account during the first five contract years. During each of the next four contract years, the daily volume Consolidated is obligated to sell and deliver to Northern will decrease by 40,000 Mcf/d, ultimately reaching zero in the tenth contract year. If Consolidated has available supply in any of the five years following the initial five-year period, it can increase the daily volume Northern is obligated to take during each of the remaining years of the contract. In this case, the daily volume in any year cannot be increased to an amount greater than the daily volume Consolidated was obligated to sell and deliver to Northern the next preceeding contract year for which the notice was given. When the daily volume is increased, an additional contract year will also be added with a daily delivery obligation equal to an amount added to the other contract years. Also, when requested by Northern, Consolidated will deliver on a best-efforts basis volumes in excess of the daily volume it is then obligated to deliver to Northern.

Columbia will purchase its gas from Columbia Gas Development of Canada, Ltd., which will obtain the gas in the Canadian Yukon Territory. Columbia Development is finalizing arrangements with Westcoast Transmission Co. for the processing and transportation of the gas to the international border at Sumas, Washington for delivery to Northwest Pipeline Corp. The gas will then be displaced to El Paso Natural Gas Co. in LaPlata County, Colorado. Once delivered to El Paso, El Paso will deliver a similar volume from its supply in the Gulf of Mexico region to Columbia Gulf Transmission Co. in southern Louisiana. Then Columbia Gulf will deliver the gas through its existing system to Columbia at existing delivery points in Kentucky.

In support of both projects, Northern and Columbia emphasized their need for these supplies to meet the long-term projected requirements of their customers.

1/ Consolidated has the option, on 24 months notice to TransCanada, to receive delivery of its gas at Monchy, Saskatchewan. The first election is not to exceed 50% of the daily contract quantity then in effect.

FERC Directs Staff to Prepare Decision Approving Great Plains Gasification Project

At an open meeting on 9/22/79, the FERC tentatively agreed in principle to reverse an initial decision by an Administrative Law Judge and clear the way for final consideration of applications relating to the Great Plains Gasification Associates (CP78-391) proposal to construct and operate the nation's first commercial coal gasification plant. No final action was taken, but Staff members were directed to prepare an order approving the proposed project subject to tariff and financing conditions.

The Commission's intent was expressed in votes on two separate motions by Commissioner George Hall. Commissioner Georgiana Sheldon joined with Commissioner Hall in voting affirmatively, while Commissioner Matthew Holden dissented. Chairman Charles Curtis is taking no part in the decision.

Commissioner Hall's first motion put the Commission on record as favoring consideration of pipeline applications seeking authorization of commercial demonstration projects even if the project costs are to be borne exclusively by the ratepayers of the participating pipelines. Administrative Law Judge Raymond Zimmet, in a 6/6/79 initial decision, had determined that such projects are of potential benefit to the entire country and hence should be financed by the nation's taxpayers rather than a given percentage of ratepayers. A Majority of the Commission also approved a second motion that the Great Plains project merits the support of the participating pipelines and should thus be approved subject to agreement on appropriate tariff and financing conditions.

The Great Plains project was initially proposed by Michigan Wisconsin Pipe Line Co. and ANG Coal Gasification Co., both subsidiaries of American Natural Resources Co., which applied in March 1975 for authority to sell SNG output (after commingling with natural gas) from a plant in Mercer County, North Dakota designed to produce an average of 250,000 Mcf/d. A year later Michigan Wisconsin and ANR revised the project so as to propose construction in two phases and to seek authority only for first phase operation (125,000 Mcf/d). At that time, the applicants estimated the plant investment cost at $538 million and the unit SNG cost at $3.52/Mcf based on 1975 cost levels.

In August 1977, the application was again amended to add Peoples Gas Co. as an equal co-partner. The two sponsors initially took the position that federal loan guarantees were essential to financing, but subsequently abandoned efforts to obtain such guarantees in favor of finding additional sponsors to share the project costs. This resulted in a restructuring of the project in June 1978 to include Columbia Gas System, Inc., Tenneco, Inc., and Transco Companies, Inc. as additional sponsors. It was agreed that the five sponsoring companies would contribute equal shares of equity funds and share the plant output equally. The Department of Energy intervened in support, citing the need to determine the practicability of manufacturing and marketing coal gas -- so that "the nation will then know whether it can turn to this technology if it ever becomes necessary."

In his initial decision, Judge Zimmet rejected the argument advanced by both the sponsors and DOE that FPC Order No. 566 provided support for funding of large scale demonstration plants by pipelines with a sufficiently large number of ratepayers to minimize the cost impact on individual consumers. Judge Zimmet argued that Order No. 566 did not address the public convenience and necessity test of Section 7 of the Natural Gas Act.

Additionally, Judge Zimmet noted that the project, even if successful, would confer no special benefit on the sponsoring companies' ratepayers because of the relatively small volume of gas which would have to be divided five ways. Moreover, ~~he observed~~, if the project fails, "the ratepayers will receive nothing at all -- other than learning along with the rest of America that we cannot rely upon this technology in the future." Learning or acquiring knowledge about coal gasificaiton, Judge Zimmet concluded, "is the very purpose, and the only real benefit, of the Mercer County project. This knowledge will inure to the nation as a whole. There is every reason for America's taxpayers to bear the costs of this project."

Assu ~~Even in the event that~~ it were found appropriate that the ratepayers of the five pipelines should bear the entire project costs, Judge Zimmet ~~added,~~ noted several aspects of the proposed financing plan still presents various problems. Among these he cited the sponsors' demand for advance assurance of equity recovery on an accelerated five-year basis if the project were aborted for reasons other than cost overruns or technological failure, the demand for a 15% return on equity throughout the life of the project, and a proposal to collect capital costs from ratepayers during project construction. (See REPORT NO. 1213, pp4-8; & 1232, pp 11-12; 1233, p 4; 1235, pp 6-7)

During the open meeting discussion of the Great Plains project, Commissioner Hall emphasized the need to consider elements other than engineering or technical capabilities in demonstrating the workability of a project. He mentioned, for example, general social and economic concerns as well as the institutional and regulatory framework within which a project must operate. The fact that a project is based on a proven technology does not resolve the question of whether it can efficiently operate within the social, economic and regulatory framework of the U.S., Commissioner Hall argued. All of these elements are obstacles and there is a need to demonstrate that they can be overcome. On that basis, Commissioner Hall contended that the Great Plains project, and others like it, should be treated as commercial demonstration projects.

Commissioner Matthew Holden took the position that such definition of a commercial demonstration project would be far too broad. Numerous unviable projects could suddenly become viable on the basis of classification as a commercial demonstration project, he noted. In short, Commissioner Holden foresaw great difficulty in limiting the definition of a commercial demonstration project under Commissioner Hall's formulation. Commissioner Hall suggested that approvals could be confined to one project for a given process for which there was a clear demonstration need and a perceived justification of costs to be expended.

The Commission plans to consider a proposed final order on the matter at its meeting on November 14.

Further Producer Sales Contracts Protested by Third Parties as Lacking Contractual Authority to Collect NGPA Prices; INGAA Objects to Commission Action on Waiver of Service Requirements

On 10/23/79 and 10/24/79 further protests to assertions of contractual authority to collect NGPA maximum lawful rates were filed pursuant to Order No. 23-B by the Associated Gas Distributors and Commission Staff. Nearly 6,000 contracts have already been contested by numerous third parties as lacking proper contractual authority. (See REPORT NO. 1231, pp1-3.)

AGD protested the asserted right to collect NGPA ceilings under 91 contracts shown in the evidentiary submission of Sea Robin Pipeline Co. (GP80-42). AGD's protest was adopted by the Gas Consumers Group, the Kansas State Corporation Commission and the Cities of Mangum, Oklahoma and Winfield, Kansas. The Staff protest alleged a lack of contractual authority for collection of NGPA rates under 41 contracts shown in the filing by Southern Natural Gas Co. (GP80-35). In each case, the protests presented arguments similar to those contained in protests filed by the same parties the previous week.

The majority of contracts protested by AGD in Sea Robin's filing contained various types of area rate clauses providing for escalations which the FPC, FERC or a successor agency may prescribe, approve, permit or establish by order, settlement or rule. AGD argued that such contract clauses do not provide requisite contractual authorization for collection of the higher NGPA prices because Congress cannot be construed to be a successor agency to the FPC; the NGPA rates were not prescribed, approved, established or permitted by the FPC or FERC but established by Congress and only implemented by FERC; and references to rates being set "by order following hearing, by settlement or rulemaking" (or such similar phrases) contemplates administrative agency actions and not legislative actions by Congress. AGD also protested certain contracts as containing no escalation provisions of any sort and/or escalation clauses providing for a fixed price. In addition, AGD protested contract clauses containing specific reference to Congressional action to the extent that such clauses resulted from amendments to existing contracts which were adopted without adequate consideration to pipeline purchasers or their customers.

The Staff protest was confined to the lack of contractual authority to collect maximum lawful prices in excess of those permitted under Section 104 of the NGPA. 1/ In support, Staff argued that the term "successor agency" or "successor governmental authority" does not refer to Congress and that the events contemplated in the area rate clauses as triggering the higher prices are administrative agency actions and not legislative enactments.

In a development related to third party protests, the Interstate Natural Gas Association of America (INGAA) on 10/23/79 requested reconsideration of a 10/11/79 FERC order which amended Order No. 23-B to provide that Federal Register notice (rather than direct service by third party protesters) would constitute adequate notice of a protest to affected parties. This action was taken in response to a petition by a group of potential third party protestors requesting waiver of the requirement to serve copies of protests on all affected producers on the grounds

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1/ Staff's protest noted that since natural gas rates were set on a cost of service basis prior to NGPA enactment, it is reasonable to assume that parties to a contract contemplated cost based increases such as those underlying Sections 104 and 106(a) of the NGPA.

that they did not have adequate access to the names and addresses of affected producers and that, even if provided such access, the expense and administrative burden imposed by the service requirement would be prohibitive in light of expected protests to some 10,000 contracts. The FERC concluded that retention of the service requirement would render the Order No. 23-B protest procedure "meaningless." To assure that producers receive adequate notice, the FERC retained the requirement that all third party protests be served on the affected interstate pipelines and directed that such pipelines mail a copy of the protest to the other party to the contract within 30 days of receipt.

INGAA noted FERC had never noticed the petition by third party protesters which led to the 10/11/79 FERC order and that no schedule for filing responses to the petition was established. In light of this procedure, INGAA stated that its response to the petition, while timely filed on 10/12/79, did not receive proper Commission consideration. In that response, INGAA suggested that interstate pipelines could provide the third party protestors with addresses of producers listed in their evidentiary submissions (to the extent these addresses are available) so as to facilitate direct service by third party protesters.

FERC Grants Rehearing for Further Consideration of Regulations Covering New Natural Gas, New Onshore Production Wells and Stripper Well Gas Under Sections 102, 103 and 108 of the NGPA; Proposed Draft Orders on Rehearing Reflect Substantial Changes

During the past 10 days, the FERC granted rehearing -- for purposes of further consideration -- of (1) Order No. 42 (RM79-68) adopting final regulations with respect to new natural gas (and gas produced from new OCS reservoirs on old OCS leases) covered by Section 102 of the NGPA; (2) Order No. 43 (RM79-72) adopting final regulations with respect to new, onshore production wells covered by Section 103 of the NGPA; and (3) Order No. 44 (RM79-73) with respect to stripper well natural gas covered by Section 108 of the NGPA. Numerous requests were filed for rehearing of all three orders.

Subsequently, on 10/23/79, the FERC issued a notice designating two Staff employees (Elisabeth Pendley and Marilyn Rand) as officers of the Commission for purposes of making copies of Staff draft orders on rehearing of the above actions available to the public. The same two employees were also made responsible for meeting with interested members of the public over the period 10/25 through 10/30/79 to discuss questions and comments concerning the Staff draft orders. 1/

The draft orders -- summarized below -- would make several significant changes in the previously adopted final regulations. (1) In the case of Section 102 gas, the Commission would adopt an economic test (as well as a physical capability test) for purposes of determining whether natural gas "could have been produced in commercial quantities" from an old well which penetrated a new onshore reservoir prior to 4/20/77 and hence whether the reservoir is subject to a "behind-the-pipe exclusion." This economic test would be based on a comparison of the minimum incremental costs and expenses which would have been required to market the gas on 4/20/77 and the total revenues which would have been generated from sale of the gas at that time. (2) In the case of Section 103 gas, the draft order would substantially modify the special rule pertaining to second wells drilled into existing proration units by eliminating the requirement that a finding of "effective and efficient drainage" regarding the second well must be made prior to drilling, eliminating the need for an "effective and efficient drainage" finding as to the new well where a jurisdictional agency creates a new prortation unit prior to drilling of a new well on the basis of effective and efficient drainage of the reservoir by the new well, and deleting the requirement for establishment of separate allowable for both the existing well and a new well in an existing proration unit. (3) In regard to Section 108 gas, the draft order on rehearing provides for further consideration of the definitions of "production day" and "90-day production period." An interim interpretative regulation has been drafted to define the term "produced" -- as used in Section 108 -- to include any day during which there is measureable production from a well and "any day on which a well is open to the line but is unable to produce measureable quantities of gas." This definition is intended to resolve problems with respect to failure of wells which are open to the line but cannot meet line pressure to qualify for stripper well status because of inability to establish a preceding 90-day production period.

New Natural Gas (RM79-68)

New natural gas, as defined in Section 102, includes (1) new onshore wells (commenced to be drilled on or after 2/19/77 located 2.5 miles or more from the

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1/ Such meetings should be arranged in advance with Ms. Rand. Telephone (202) 357-8672.

nearest "marker well," or completed at least 1,000 feet (measured by true vertical depth) below the deepest completion location of any "marker well" within 2.5 miles; (2) new onshore reservoirs from which natural gas was not produced in commercial quantities prior to 4/20/77 -- excluding "behind-the-pipe" gas (reservoirs penetrated before 4/20/77 by an old well from which natural gas or crude oil was produced in commercial quantities, or from which natural gas "could have been produced in commercial quantities"), and "withheld gas" (produced from an old well where "suitable" facilities for production and delivery to a pipeline were installed or "substantially installed" on 4/20/77); and (3) new OCS leases (entered into after 4/20/77). Section 102 also covers new OCS reservoirs (discovered after 7/27/76) on old leases (entered into before 4/20/77).

One major issue respecting the Regulations developed by the Commission thus far to implement Section 102 relates to the "behind-the-pipe" exclusion, particularly the meaning of the phrase "could have been produced in commercial quantities." In both the Interim Regulations (issued 12/1/78) and in Order No. 42 issued 8/14/79, the Commission adopted a physical capability test for purposes of interpreting this phrase. Order No. 42 stressed language in the Conference Report specifying that the term "could have been produced" was intended to refer to the "capability of the reservoir to produce without regard to whether actual production capability existed." The text of the statute, the legislative history and policy considerations all allow use of a capability test for the term "could have been produced" in the "behind-the-pipe" exclusion, the Commission declared, and this capability test does not take account of the necessity for or cost of pipeline facilities, gathering or processing plants. Thus, costs and prices -- regardless of time reference -- are "irrelevant." (See REPORT NO. 1223, pp1-2.)

Nearly all of the applications for rehearing of Order No. 42 protested the Commission's refusal to apply an economic test to the term "could have been produced in commercial quantities." Application of a physical test alone was said to contradict the customary usage of the phrase "commercial" and to ignore the legislative intent of the NGPA to encourage the production of previously uneconomic reserves.

The draft order proposed to adopt both a physical capability test and an economic test for determining the applicability of the "behind-the-pipe" exclusion to a particular reservoir. The economic test would be based on a comparison of (1) the minimum incremental costs and expenses which reasonably would have been required as of 4/20/77 to produce and market the gas, and (2) the total revenues which would have been generated from the sale of the gas at the market price as of 4/20/77. If a net profit could reasonably have resulted, then it would be concluded that the reservoir "could have been produced in commercial quantities" prior to 4/20/77 and that the "behind-the-pipe" exclusion would apply. 1/

In order to implement this economic test (which need only be made once for each reservoir), an applicant must submit (1) estimated known natural gas and gas liquid reserves as of 4/20/77 (net of royalty) producible from the subject reservoir and attributable to each old well that penetrated the subject reservoir which produced crude oil or natural gas in commercial quantities prior to 4/20/77; (2) a reserve study explaining all assumptions made in estimating reserves as of 4/20/77, together with a gas analysis showing the wellhead Btu, sulfur, carbon

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1/ This proposed economic test was discussed (but not adopted) in a Commission open meeting on 9/27/79. At that meeting, the Commission affirmed certain North Dakota jurisdictional agency determinations which were previously reversed on grounds of the "behind-the-pipe" exclusion. (See REPORT NO. 1228, pp28-30.)

dioxide or other impurities content of the gas; (3) estimated incremental costs of installing and operating the minimum additional facilities which were not in existence on 4/20/77 and which would have been required to market the gas on that date, together with evidence justifying the size, configuration, type, location and cost of such facilities; (4) market price evidence -- including the highest price for natural gas of similar quality applicable under the Natural Gas Act as of 4/20/77, the price or prices actually received for sale of the subject reserves if sales commenced after 4/20/77, the highest price paid for reserves of similar quality and marketability on or before 4/20/77 from the area of the sale, the price or prices offered prior to 4/20/77 for purchase of the subject reserves, and any other evidence of market price as of 4/20/77; and (5) evidence supporting the allocation of costs and expenses to natural gas and natural gas liquids where jointly produced. However, in order to reduce the submission of the economic data and analyses described above, the draft order proposed to create a "rebuttable presumption" that a reservoir could not have been produced in commercial quantities prior to 4/20/77 through a well drilled prior to 2/19/77 if no sales and deliveries from any other reservoir were made prior to 4/20/77 through such well and if no sales and deliveries from the subject reservoir were made through such well between 4/20/77 and 10/31/79. The draft order said this "rebuttable presumption" should limit the submission of cost, reserves and price information needed for an economic analysis to those applicants who are most likely to be seeking incentive prices now for the sale of reserves that could have been produced in commercial quantities when viewed as of 4/20/77.

The draft order stated that this incremental out-of-pocket economic test -- which specifically excludes consideration of any return, cost of capital, recovery of pre-4/20/77 investment, or federal income taxes -- "embraces the Congressional intent of Section 102 of the NGPA." Specifically, the draft declared, the contemplated test will encourage production of clearly noncommercial reserves but, by denying recovery of sunk costs and a return on that investment, will prevent application of the Section 102 maximum lawful price to gas which was not produced because of a desire for greater profits. Moreover, the draft added, "basic economic theory dictates that such a decision should be made by considering only incremental expenditures and incremental revenues. Expenditures incurred prior to the date of the decision are irrelevant to that decision. For purposes of the behind-the- pipe exclusion, the decisional date is 4/20/77."

The above described economic test and associated reporting requirements would be issued as interim regulations -- with an opportunity for public comment -- effective immediately as to all applications for which jurisdictional agency determinations have not yet been made. In the case of determinations already received by the Commission for which the 45-day review period has not expired, applicants would be afforded an opportunity to supplement their filings, in which case the Commission would remand the determinations to the jurisdictional agencies for reconsideration.

With respect to new OCS reservoirs discovered after 7/27/76 on old OCS leases, the draft order would modify the definition of "commercially producible" for purposes of determining whether a reservoir was discovered on or after 7/27/76. (Among other tests, Section 102(d)(2) provides that a reservoir will be deemed "discovered" prior to 7/27/76 if certain logs, sidewall cores and other test data indicate the reservoir to be "commercially producible" at the time of the test.) Whereas Order No. 42 defined "commercially producible" for OCS reservoirs by reference to the definition of the term "production in commercial quantities" for onshore reservoirs (i.e., production which is either sold and delivered to someone other than the operator or which is retained for beneficial economic use), the

draft order agreed with one commenter that these two definitions should not be linked. Instead, the draft order would apply the same out-of-pocket cash expense test adopted to determine the capability of a well to produce in "paying quantities." However, the draft order rejected a recommendation by the Indicated Producers that this economic test be expanded to include all costs incurred after the date of the production test (such as the cost of additional platforms and pipelines) in order to sell and deliver the subject gas.

This change would be effective immediately as an amendment to the final regulations previously adopted in Order No. 42.

New Onshore Production Wells (RM79-72)

The draft order on rehearing of Order No. 43 would relax the special rule (Section 271.305) applicable to second wells drilled into existing proration units in several respects.

As adopted in Order No. 43, the special rule allows second wells drilled in existing proration units to qualify as new onshore production wells eligible for Section 103 pricing only if the jurisdictional agency explicitly finds -- prior to commencement of drilling -- that the second well "is necessary to effectively and efficiently drain a portion of the reservoir covered by the proration unit which cannot be effectively and efficiently drained by any existing well within the proration unit." (In the case of wells spudded between 2/19/77 and 12/31/78 for which a drilling permit was issued prior to 1/1/79, the rule permits an implicit rather than explicit finding of efficient and effective drainage prior to commencement of drilling under certain conditions.) The explicit finding must be based on appropriate geological and engineering data, which data shall be included in the jurisdictional agency's notice of determination submitted to the Commission. Order No. 43 further required that, where a state agency establishes allowables or production levels for proration units, the agency must set separate allowables for both the existing well and the new well in the unit in order for the new second well to qualify for the Section 103 price. (See REPORT NO. 1223, pp2-4.)

As a first modification of Order No. 43, the draft order would delete the requirement for establishment of separate allowables for all wells in a unit. Intended to deter disproportionate production from a second new well in a unit because of eligibility for a higher price, this requirement was widely attacked as an unlawful attempt by the Commission to intrude into the regulatory area of gas production which is reserved to the states. The requirement was also attacked as inequitable, discriminatory in effect, and unduly burdensome both administratively and economically on jurisdictional agencies. In consideration of the comments, the draft order concluded that further expression of views by interested and affected parties would be beneficial and hence provided for institution of a rulemaking proceeding to address the questions raised. In the meantime, the allowable requirement would be withdrawn.

Second, the draft order would modify the Order No. 43 regulations to eliminate the requirement that the effective and efficient drainage finding be made prior to drilling the second well. The draft order noted contentions that procedures are not available in some states (such as Oklahoma) to make the requisite finding prior to drilling. The draft order agreed with comments that a more accurate determination regarding the need for a new well could be made after drilling and that unnecessary delays could result from retention of the requirement for a finding of efficient and effective drainage prior to drilling.

Third, the draft order adopted the Indicated Producers' suggestion that any well plugged and abandoned prior to 1/1/70 (and not produced after that date) should not be considered an "existing well." More specifically, the draft order would create a rebuttable presumption that such a well has not produced natural gas in commercial quantities.

Finally, in response to arguments by the State of Texas and others, the draft order provided that where a jurisdictional agency creates a new proration unit prior to the drilling of a new well on the basis of effective and efficient drainage of a reservoir by the new well, the Commission will recognize the newly created unit for the purpose of approving Section 103 determinations and will not require the effective and efficient drainage finding under Section 271.305 with respect to the new well. Previously, in Order No. 43, the Commission rejected this approach and instead required that redefinitions of proration units must be accompanied by findings respecting effective and efficient drainage of the existing proration unit before a new well drilled in a former unit could qualify for Section 103 pricing.

Stripper Well Gas (RM79-73)

Under Section 108(b)(1) of the NGPA, a well qualifies as a stripper well if, during a 90-day production period prior to the date of application to the jurisdictional agency, it produced nonassociated gas at a rate not greater than an average of 60 Mcf per production day when producing at its maximum efficient rate of flow. The statute also provides that a well may continue to qualify as a stripper well if production exceeds 60 Mcf/d during any 90-day production period, provided the increased production resulted from application of recognized enhanced recovery techniques. Order No. 44 (issued 8/22/79) revised the Interim Regulations adopted on 12/1/78 in several respects, including amendment of the definitions of "recognized enhanced recovery techniques," "90-day production period" and "production day," among other things. (See REPORT NO. 1223, pp5-7.)

The draft order would grant rehearing of the Order No. 43 definitions of "production day" and "90-day production period" for purposes of further consideration. An interim interpretative regulation has been prepared for concurrent release to define the term "produced" (as used in portions of Section 108 of the NGPA) and to clarify the terms "production day" and "90-day production period."

Other than the changes set forth in this regulation, the draft order would deny rehearing. In particular, the draft rejected a request by the State of Texas to delete the requirement that jurisdictional agencies define the term "normal completion operation" with respect to wells within each state for purposes of determining the application of "recognized enhanced recovery techniques" (which exclude normal competion operations performed within two years of initial well completion). Texas contended that any comprehensive definition of "normal completion operation" would be unduly burdensome because of the diverse geographic, geological, economic and engineering factors among wells and fields within the State of Texas. The draft order took the position that diverse factors indigeneous to each locale necessitate state by state determinations of normal well completion operations. Furthermore, the draft order asserted, the benefits derived from such determinations should far outweigh the burdens. The draft order noted, for example, that Texas will not be required to review each of the producing wells within the state as contended. A number of Section 108 stripper natural gas wells probably will not apply for recognized enhanced recovery techniques; most well determinations which do involve recognized enhanced recovery techniques concern old wells, and these determinations do not raise the issue of "normal completion operations."

The interim interpretative regulation (draft version) -- which stems from Commission review of certain types of jurisdictional agency well determinations under Section 108 1/ -- would amend the regulations (Section 271.803) to add the following definition: "Any day during which natural gas is 'produced' means (1) any day during which there is measureable production from a well, and (2) any day on which a well is open to the line but is unable to produce measureable quantities of gas."

The draft regulation explained that the phrase "open to the line" is intended to permit stripper well qualification for wells which cannot produce because they are unable to meet line pressure. To date, in various preliminary notices of reversal of jurisdictional agency well determinations, the Commission has rejected stripper well status for such wells because of inability to establish a preceding "90-day production period" (which is defined to exclude involuntary nonproducing days"). Definition of the term "produced" to encompass days when the well was in a production mode but unable to produce would resolve this problem, the draft regulation explained, because such days would no longer be regarded as nonproducing days and hence would not have to be excluded from the 90-day production period.

The new definition of "produced," the draft regulation continued, is also intended to encourage renewed production from shut-in wells and continued production from irregularly-producing wells by enabling them to qualify for the stripper well price. Once a well qualifies for the stripper price, the draft noted, a producer who installs a process or equipment qualifying as a "recognized enhanced recovery technique" to increase the rate of production may still receive the stripper well price if average production is increased through such technique above 60 Mcf per production day. Accordingly, "it may become economically feasible for the producer to perform an enhanced recovery technique on a low production well once the likelihood of qualification for the Section 108 price is established. In this way, gas which might otherwise be lost may be recovered."

The draft regulation added that the definition of "produced" does not cover days when a well is shut in by the operator. However, such days may qualify as "production days" if the jurisdictional agency makes a finding that prudent conservation practices require intermittent shut-in of the well and explains why the conservation practice applied to a particular well is necessary to achieve and maintain production. The Commission would consider such a finding and explanation to constitute substantial evidence that the shut-in days meet the statutory test for "production days." On the other hand, voluntary shut-in days would not be deemed to meet the statutory definition of "production day." To permit such days to qualify as "production days," the draft stated, would be to invite manipulation of production in order to qualify for the Section 108 incentive price.

The interim interpretative regulation would be made effective immediately but would not become final until interested parties had an opportunity to submit written and oral views.

1/ The draft regulation noted problems in regard to three categories of wells which have been preliminarily determined by the Commission not to qualify as stripper wells because of no "production days" or "90-day production periods": (1) wells shut-in due to inability to meet line pressure; (2) open valve wells (i.e., wells open to the line but unable to meet line pressure); and (3) intermittent production or "burping" wells (i.e., wells which are open to the line and produce natural gas at irregular intervals when sufficient pressure builds up over a period of time to permit the well to "burp up" a measureable amount of gas).

FERC Acts on Petitions for Rehearing of Order No. 29 Adopting Permanent Rule to Implement Agricultural Priority Provisions of NGPA

On 10/22/79 the FERC issued Order No. 29-C (RM79-15) essentially denying applications by numerous parties for rehearing of Order No. 29 adopting a permanent rule to implement Section 401 of the ~~Natural Gas Policy Act which~~ NGPA provides for protection of essential agricultural users ~~of~~ natural gas ~~from~~ delivers curtailments by interstate pipelines unless the gas is needed for protection of higher priority uses (as defined ~~in~~ the NGPA) or unless an alternate fuel is determined to be "economically practicable" and "reasonably available." The permanent rule directs a reordering of priorities in interstate pipeline curtailment plans, to be effective on 11/1/79, when it will replace an interim rule (RM79-13) adopted by the FERC on 3/6/79 to cover the period 4/1/79 through 10/31/79.

Background

Under Section 401(a) of the NGPA, the Secretary of Energy ~~was directed~~ to prescribe a rule, within 120 days of enactment, to protect essential agricultural uses from curtailment ~~of natural gas deliveries by interstate pipelines~~, unless the gas ~~is~~ needed to protect higher priority uses (as defined in the NGPA) or unless it is determined that an alternate fuel is "reasonably available" and its use is "economically practicable." 1/ Section 401(c) directed the Secretary of Agriculture to certify ~~essential agricultural use~~ nat. gas requirements necessary ~~for~~ to meet "full food and fiber production" to the DOE Secretary and the FERC. 2/ Section 401(b) directed the FERC to determine whether an alternate fuel for an essential agricultural use is "economically practicable" and "reasonably available." Also, ~~under Section 403(b),~~ the FERC ~~is required~~ was ordered to implement the agricultural priority rule prescribed by the Secretary of Energy. by Section 403(b)

The interim rule promulgated by the FERC on 3/6/79 provides for grant of adjustments by interstate pipelines to meet supply deficiencies of essential agricultural users up to the lesser of the volumetric requirements certified by the Secretary of Agriculture or the amount the pipeline is obligated to supply under

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1/ On 3/9/79, ERA adopted a final rule providing that, to the maximum extent practicable, no curtailment plan of any interstate pipeline may provide for curtailment of deliveries of natural gas for any essential agricultural use, unless (1) such curtailment does not reduce the quantity of gas delivered for such use below the requirements certified by the Secretary of Agriculture; (2) such curtailment is necessary to meet the requirements of higher priority users; or (3) the FERC, in consultation with the Secretary of Agriculture, determines that an alternate fuel is "reasonably available" and "economically practicable." (See REPORT NO. 1200, pp13-16.)

2/ On 5/17/79 the USDA published its final rule (effective 5/14/79) which substantially modified an interim rule issued 2/26/79 by certifying natural gas requirements at 100% of current requirements for each essential agricultural use. Originally, the USDA proposed a 100% current requirements approach, but only for all on-farm uses and for essential agricultural uses consuming 300 Mcf or less per peak day. In the case of all other essential agricultural uses, the interim rule certified natural gas requirements at the higher of actual usage during the highest year of the most recent rolling three-year base period (corrected upward to include past curtailments of process and feedstock requirements and requirements not used because of plant shutdowns) or the maximum volumetric entitlement of each essential agricultural user under its interstate pipeline supplier's then effective curtailment plan. (See REPORT NO. 1210, pp1-3.)

the applicable contract. To implement this rule, the FERC directed each interstate pipeline to file before 3/16/79 a new tariff provision analogous to existing provisions affording relief from curtailment in the event of danger to life, health and physical property.

Order No. 29 requires interstate pipelines to amend existing curtailment plans ~~(or file initial plans if none exist)~~ so as to establish a new Priority 1 covering high priority users (defined as persons using natural gas in a residence, a small commercial establishment, a school or hospital, or for police and fire protection, sanitation or correctional facilities), and a new Priority 2 covering essential agricultural users (defined as persons using natural gas for "essential agricultural uses" certified by the Secretary of Agriculture). All categories in existing pipeline curtailment plans ~~are to~~ must be placed below these two new priorities. Storage injections are to be treated as in currently effective curtailment plans. Hence, pipelines which follow a "sprinkling" approach will include some storage volumes in the new Priorities 1 and 2, while pipelines which do not use a "sprinkling" method will retain storage volumes in the priorities in which they are now reflected. Pipelines are to file these amended plans by 10/1/79, together with indexes of entitlements for each direct sale customer, each local distribution company, and each interstate pipeline purchaser.

The final rule also (1) adopted the USDA's certification of essential agricultural uses -- except that interstate pipelines will not be required to make deliveries in excess of volumetric limits in their contracts with customers (the USDA certified essential agricultural uses without regard to contract or service limitations); (2) specified procedures for requesting reclassification of entitlements as Priority 1 or Priority 2; and (3) provided that high priority and essential agricultural requirements shall be attributed among suppliers based on underlying curtailment plans of interstate pipeline suppliers.

On 6/15/79, the FERC issued Order No. 29-A clarifying that Order No. 29 incorporated the USDA rule published on 5/17/79. Hence, under the permanent curtailment rule, all essential agricultural users, as defined by USDA, are entitled to request current requirements for their essential agricultural uses.

Applications for rehearing by numerous parties asserted, among other things, that (1) Order No. 29 is not coordinated with the implementation of Sections 401(b) (restricting curtailment priority if the Commission finds an alternative fuel is available) and Section 402 (giving priority to essential industrial process and feedstock uses); (2) the NGPA does not require or intend that interstate pipelines reprioritize their existing curtailment plans; (3) the Commission established a single inflexible curtailment plan applicable industrywide; (4) Order No. 29 is inconsistent with various provisions of the Natural Gas Act; and (5) the Commission should have required local distributors to deliver gas to end users to whom agricultural uses are attributable. (See REPORT NOS. 1191, pp5-13; 1193, pp17-19; 1195, pp2-5; 1199, pp11-18; 1200, pp13-16; 1202, App. pp1-13; 1206, pp1-4; 1207, pp1-4; 1210, pp1-3; 1213, pp20-28; 1214, pp10-11.)

Order No. 29-C

First, the Commission rejected the argument by several parties that Order No. 29 is not coordinated with implementation of Section 401(b) (alternative fuel) and Section 402 (essential industrial process and feedstock uses). "It is the Commission's view that its obligations under the NGPA do not permit any further delay in the final implementation of Section 401(a). That section is subject to a statutory deadline. Sections 401(b) and 402 are not. Congress clearly intended that

implementation of Section 401(a) should be given precedence if similarly expeditious implementation of Sections 401(b) and 402 was not possible." The Commission emphasized that because of different data required for implementing those sections and the need to coordinate rulemaking among USDA, ERA and the Commission, simultaneous implementation of all sections of Title IV would be impossible without substantial delay of a final rule under Section 401(a).

Next, the Commission dismissed an argument of Columbia Gas Transmission Co. that the NGPA does not require or intend that interstate pipelines reprioritize their existing curtailment plans and that, instead, the Commission should adopt a final rule based on exemption procedures similar to the interim rule. First, the Commission said, the NGPA does contemplate that interstate pipelines may be required to reprioritize their existing curtailment plans to the extent necessary to comply with Title IV. This is reflected in the specific statement in the Conference Report that "'for purposes of implementing this section, the Commission is instructed to reopen curtailment plans only to the extent necessary to adjust those plans to bring them into conformity with the new curtailment priority schedule.'" Second, the Commission said, the ERA rule implementing Section 401 provides that the relative order of priorities in existing curtailment plans will remain unchanged only if they do not conflict with the required protection of high priority and essential agricultural uses. "Although a rule establishing exemption procedures may be one way of resolving such a conflict, it is not the only way. We understand the ERA rule as providing that, in cases of conflict, the priorities of existing curtailment plans may be changed. This interpretation is consistent with the Conference Report, which assures the Commission that it "'has the necessary flexibility in implementing any changes.'" Third, the Commission noted that the interim rule established procedures whereby agricultural users could request adjustments from their suppliers in case of supply deficiencies. However, this "ad hoc" approach -- which may provide adequate protection during the summer when supplies are sufficient so that agricultural users do not have to seek relief on a large scale, but not in the winter when numerous requests for adjustments could be expected -- could be an "awkward device" creating much uncertainty. Hence, Order No. 29, which establishes priorities in advance of curtailment and allows pipelines and their customers to plan accordingly, is more appropriate on a permanent basis.

The Commission was unpersuaded by contentions of United Gas Pipe Line Co., Columbia Gas Transmission Corp. and the State of Louisiana concerning an alleged inflexibility of Order No. 29. Columbia Gas, for example, argued that the rule would prevent a pipeline from tailoring any curtailment plan to the particular circumstances existing on its own system. The Commission observed, however, that it was not inflexible in applying Order No. 29. "Where the rule was obviously unsuited to the system of a particular pipeline, it has not been applied. The Commission has also evinced flexibility in molding curtailment plans in the settlement context. If petitioners believe the rule unsuited to individual pipeline curtailment plans, the appropriate avenue for relief is a 502(c) adjustment or offer of settlement, not rehearing of the rule." 1/

The Commission then discussed arguments by the Process Gas Consumers Group that it failed to determine whether Order No. 29 meets the standards of the Natural Gas Act; Columbia Gas and Louisiana that the FERC lacks authority to prevent pipelines from filing, under Section 4, a plan that does not comply with Order No. 29 but still adequately protects high priority and essential agricultural uses; and

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1/ Section 502(c) provides for adjustments to "prevent special hardship, inequity, or unfair distribution of burdens."

Louisiana and United that the Commission establish new priorities for any pipeline without at the same time complying with Section 5 requirements.

While the NGPA did not repeal the Natural Gas Act, the Commission said, "it did modify the NGA to require a higher level of protection for essential agricultural uses than for industrial uses." Furthermore, the Commission continued, Order No. 29 was promulgated to implement requirements of Section 401, and satisfies the statutory requirements of Section 401 and Section 4 of the NGA, as modified by the NGPA. Specifically, the rule requires 37 named interstate pipelines to implement Section 401 in a particular and detailed manner. While interstate pipelines may file plans under Section 4 of the NGA that deviate from Order No. 29, such a filing by itself would not waive the requirement to file in accordance with Order No. 29 unless the pipeline has received a Section 502(c) adjustment. "A deviant plan filed under Section 4 of the NGA cannot go into effect until the requirements of Order No. 29 have been waived." The Commission added that because of time restrictions, a Section 5 proceeding would be "a wholly inappropriate vehicle" for implementing Section 401.

Next, the Commission declined arguments of American Bakers Association, Allied Chemical Corp. and others that it must require local distributors to deliver gas to end users to whom agricultural uses are attributable. "Nothing in Section 401 indicates an intention to expand the Commission's jurisdiction to include local distributors." There are "sound policy reasons" for this, the Commission explained. First, it would create inevitable conflict with local regulatory agencies. Second, it would not be feasible for the Commission to administer workable curtailment plans for the thousands of local distributors throughout the country. State agencies, on the other hand, are in a position to know the practices and requirements of local distributors and their customers. Third, if conditions requiring flowthrough of gas were imposed, the Commission would face the dilemma of applying such conditions only for high priority and essential agricultural uses, or reopening every curtailment plan to provide flowthrough to all priorities.

Although denying rehearing in virtually all respects, the Commission modified the attribution formula -- which apportions high priority and essential agricultural requirements -- so as to better conform to its intent to attribute exactly 100% of essential agricultural requirements by essential agricultural users; clarified that Order No. 29 was not intended to exempt small distributors from curtailment as provided in many pipeline curtailment plans; and changed provisions which limit protests to customers of interstate pipelines and complaints to aggrieved direct customers and distributors, so as to allow full participation by "all interested persons."

Recent Incremental Pricing Developments

On 10/15/79 Senator Henry Jackson (D-Wash.) introduced a resolution (S. Res. 255) to disapprove a proposed FERC incremental pricing rule (Order No. 51) -- transmitted to Congress on 10/11/79 pursuant to Section 206(d) of the NGPA -- to exempt, until 11/1/80, industrial boiler fuel facilities from incremental pricing above the price level of No. 6 high sulfur fuel oil in the incremental pricing region in which each such facility is located. The resolution was referred to the Senate Committee on Energy and Natural Resources. A spokesperson for that Committee has advised that the resolution was introduced merely as a procedural mechanism to facilitate bringing the FERC proposal to a floor vote, should any Senator request such a vote. The Senate Energy Committee, however, plans no hearings or any other action respecting the resolution.

Under Section 206(d), the Senate and House have 30 days of continuous session to disapprove a proposed exemption from the incremental pricing regulations under Sections 201 or 202. This period will expire on 11/10/79 as to the FERC's currently proposed exemption. Hence, barring unexpected developments, incremental pricing will commence to be implemented on 1/1/80 using a single high sulfur No. 6 alternative fuel cost ceiling, which will be determined and published monthly by the Energy Information Administration for each of the 48 contiguous states.

Order No. 51 was one of several rulemaking orders and related rulemaking notices issued by the FERC on 9/28/79 to implement Phase I of the incremental pricing program directed in Title II of the Natural Gas Policy Act. 1/

In Order No. 50 (RM79-21), the FERC adopted a three-tier system of alternative fuel price ceilings for purposes of computing the capacity of industrial boiler fuel users to absorb gas acquisition costs subject to incremental pricing. The three alternative fuels are No. 2 fuel oil, low sulfur No. 6 fuel oil (1% or less sulfur) and high sulfur No. 6 fuel oil (over 1% sulfur by weight). The Commission concluded that this three-tier approach -- by avoiding loss of industrial gas load with No. 6 fuel oil burning capability while maintaining the contribution of

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1/ Section 201 of the NGPA directed the FERC to promulgate a rule, within 12 months from enactment (or by 11/9/79), providing for passthrough of specified portions of certain gas acquisition costs incurred by interstate pipelines to industrial boiler fuel users of natural gas (excluding small industrial boiler fuel facilities in existence on 11/9/78 which used less than 300 Mcf/d during a base period deemed appropriate by the Commission). Within 18 months from enactment (or by 5/9/80), Section 202 requires that the Commission amend the rule to provide for passthrough of the same types of gas acquisition costs to other industrial facilities using natural gas, subject to various exemptions. (The second rule, but not the first, is subject to Congressional review.) The gas acquisition costs subject to incremental pricing are to be passed through via surcharges to affected users until the amount paid by such users for natural gas equals the Btu equivalent price of substitute fuel oil which, unless otherwise determined by the Commission, shall be the average price paid by industrial users for No. 2 fuel oil on a regional basis. However, under Section 204(e), the FERC may, by rule or order, reduce the appropriate alternative fuel cost ceiling to the level of No. 6 fuel oil prices paid by industrial users on a regional basis if it determines that such reduction is necessary to prevent rate increases to residential, small commercial and other high priority natural gas users due to reallocation of costs caused by conversion of industrial facilities from natural gas to other fuels.

industrial users with No. 2 capability to recovery of incremental costs -- best satisfies the Congressional intent underlying Section 204(e) of the NGPA. Nevertheless, the Commission expressed various concerns regarding immediate implementation of the three-tier system and accordingly determined that deferral of the two highest alternative fuel price ceilings for a 10-month period would be in the public interest.

To accomplish this deferral, in Order No. 51 provided for exemption of industrial boiler fuel facilities from incremental pricing above the price of No. 6 fuel oil until 11/1/80 (subject to Congressional disapproval, as noted above). In support, the Commission emphasized the possibility of significant "induced" investment in No. 6 oil burning capability merely to attain the advantage of a lower ceiling for incremental pricing purposes. While unable to estimate precisely the extent of such "induced" investment at this time, the Commission noted a widespread potential for conversion from No. 2 fuel oil backup capability to No. 6 capability -- involving possibly "large" aggregate national costs with little or no public benefit. The Commission also suggested that any widespread conversion from No. 2 to No. 6 backup capability would leave a de minimis amount of industrial boiler fuel load available to be incrementally priced at the No. 2 level. In that event, the benefits of a three-tier approach to residential and commercial customers would not be substantially greater than the benefits under a single No. 6 high sulfur ceiling. The Commission further stressed the administrative, data gathering and enforcement burdens entailed by a three-tier system. Among other things, the Commission observed, EIA has experienced difficulty in developing three sets of accurate price ceiling for each of several regions, and this task would be greatly simplified if only one ceiling were required per region. Based on these and certain other considerations, the FERC generally concluded that deferral of the two upper tier alternative fuel cost ceilings for a period of 10 months would provide time to gain a better understanding of the incremental pricing program and to ease its implementation.

In Order No. 49 (RM79-14), the FERC adopted a "reduced PGA" mechanism for calculation and billing of incremental pricing surcharges, and established a self-certification affidavit procedure for identifying boiler fuel facilities which are statutorily exempt from incremental pricing under Section 206. These regulations will be effective 11/1/79, except that provisions governing procedures for obtaining exemptions will be effective 10/15/79 in order to permit the calculation of "reduced PGA" rates by 12/1/79. (Numerous exemption affidavits have been received by the Commission during the past week.) The regulations require that incremental gas costs commence to be booked by natural gas suppliers as of 1/1/80, and that billing for incremental surcharges commence for nonexempt usage during January 1980.

One issue raised in connection with the Commission's proposed surcharge pass-through mechanism involved the use of submeters to determine nonexempt volumes. In Order No. 49, the FERC adhered to ~~its~~ its prior conclusion that installation of submeters is the only available means to ensure implementation of the incremental pricing program in the manner envisioned by Congress. However, the Commission decided to delay mandatory installation of submeters until 11/1/80 -- after the establishment of regulations to implement Phase II of the incremental pricing program -- and to permit use of estimates and/or supplier customer agreements to determine nonexempt volumes in the interim. After 11/1/80, absent an installed operational submeter (or one on order), the Commission will deem all volumes sold to a nonexempt industrial boiler fuel facility as subject to incremental pricing. At the same time, the Commission recognized problems raised by various parties in opposition to a mandatory submetering requirement and ~~announced its intent to~~ hence provided for a technical conference to discuss these problems, as well as developed standardized estimates to be used during the interim period.

schedule a technical conference on these problems in November. (See REPORT NO. 1229, App. pp12-14.)

Recently, on 10/19/79, the FERC issued notice that the technical conference mentioned in Order No. 49 will be held 11/15/79 in Chicago to discuss estimates and submetering requirements. The conference will be chaired by the Commission's Technical Staff and will continue the next day if necessary. In regard to estimates, the notice said the Commission desires to standardize estimating procedures to the extent possible. Hence, parties were invited to describe their intended approach to preparing estimates so that the Staff may develop and issue suitable guidelines prior to 1/1/80. The notice also invited persons who previously prepared estimates of boiler fuel (and other) consumption, but who subsequently installed submeters to determine such usage, to describe their experience as to how valid the estimates have proven and their reasons for abandoning estimates in favor of meters. Finally, comments are requested on estimating procedures which should be used in two problem situations, namely, where steam raised or electricity generated by a boiler fueled with natural gas is used for both exempt and nonexempt purposes, and where a mixed stream of gas (natural gas commingled with gas from another source such as coke oven gas or refinery by-product gas) is used to fuel a boiler.

As to submeters, the Commission Staff seeks views on whether submeters can be installed in all affected industrial facilities to measure (either directly or indirectly) volumes used for boiler fuel, and on the number of submeters which need to be installed by 11/1/80, as well as the time required for their manufacture and installation. In addition, Staff seeks information from representatives of meter manufacturing firms on the types of meters available, application techniques, representative costs, and methods for maintaining accuracy and for correcting meter readings to standard pressures, volumes and temperatures.

In addition to the technical conference on submetering requirements and estimation procedures, the FERC has scheduled an informal question and answer session on Phase I incremental pricing regulations for 10/31/79 in Chicago. The session will be held at the Center Theater, DePaul University, 21 East Jackson Boulevard, Chicago, Illinois beginning at 9 a.m.

ERA Holds that Issue of Incremental Pricing Remains Open in Proceeding Involving Proposal for Automatic Price Increases for Imported Algerian LNG

On 10/18/79 the ERA denied a motion by the Peoples Counsel of Maryland for modification of its order of 9/24/79 -- which set a hearing for 10/30/79 on a joint application by Columbia LNG Corp., Consolidated System LNG Co. and Southern Energy Co. (79-14-LNG) for automatic price increases for Algerian LNG imported to Cove Point, Maryland and Elba Island, Georgia -- so as to require the applicants to prove that incremental pricing should not be required by the ERA. However, the ERA made clear that the issue of incremental pricing remains open in this proceeding, although the burden of demonstrating that it is in the public interest must be borne by those advocating that position. Moreover, the ERA concluded that the applicants' proposal for a substantially higher import price requires that all aspects of previous orders in this proceeding dealing with the subject of price be reopened to consider, among other things, whether the LNG importers should be permitted to contract directly with distribution companies.

The application here involved would amend FPC Opinion Nos. 622 and 622-A (and related ERA and FERC orders) -- authorizing importation of a total 1 Bcf/d equivalent of LNG from El Paso Algeria Corp. -- so as to adjust the base price beginning 1/1/80 based upon certain automatic price escalator provisions. Earlier, the ERA granted the joint application insofar as it sought an increase in the base price (f.o.b. Arzew, Algeria) from 39¢ to $1.15/MMBtu for the period 7/1/79 through 12/31/79. However, the ERA refused to approve further adjustments based on automatic f.o.b. price escalator provisions totally linked to the prices of fuel oils. This, the ERA said, would remove pricing determinations for LNG from the Federal Government and place it in the hands of the world's oil cartel. These provisions, the ERA concluded, require further examination. In its order, the ERA requested evidence on, among other things, whether the proposed LNG price and price escalator are reasonable, and whether the gas should be incrementally priced to the distribution companies and, if so, the effect thereof on consumers. The ERA scheduled a hearing for 10/30/79. (See REPORT NOS. 1211, pp1-2; 1217, pp21-22; 1219, pp27-28; 1224, pp18-20; 1227, pp25-27; 1229, p21.)

In its order, the ERA first denied Maryland's motion that the applicants should bear the burden of proving that incremental pricing should not required in this proceeding. The ERA said it remains open to the argument on post-hearing brief that it is mandated to order incremental pricing in this case under the NGPA, although it believes that it has authority to do so under Section 3 of the Natural Gas Act if it is found to be in the public interest. Nevertheless, the ERA emphasized that the burden of demonstrating that incremental pricing is in the public interest properly should be borne by those advocating that position rather than the applicants. "In ERA's opinion, the type of information that could be presented to demonstrate that incremental pricing is necessary or appropriate in this proceeding is not uniquely in the possession of the applicants, and the parties advocating incremental pricing can and should present such evidence as part of their direct case."

However, the ERA agreed with a further argument of Maryland that the applicants -- rather than interveners -- must assume the burden of proving that the direct sale of the LNG involved in this case to distributors is practicable and in the public interest and that such customers are in fact willing to enter into direct contracts at the proposed higher prices.

Maryland noted that in the 9/24/79 order, the ERA stated that direct contracting for sales of the regasified LNG with distributors is a form of incremental pricing and, at the same time, held that those favoring incremental pricing must have the burden of demonstrating that it is practicable and in the public interest. Accordingly, Maryland was concerned that the ERA was placing this burden on interveners who support direct contracting with distributors. Maryland requested clarification that the burden of proof on direct contracting -- which the ERA has previously held to be a way of assuring an actual need for the LNG -- will be borne by the applicants. Maryland further emphasized that the question of directly committing imported LNG to distributors is completely independent of the issue of incremental pricing. In previous decisions, Maryland said, the ERA has considered transactions involving direct commitment of supplies to distributors as reflecting a need for the LNG. Hence, in this case, the applicants must bear the burden of showing that the distributors will directly contract for the LNG, or such presumption should not be followed in this case. Subsequently, the applicants responded that this proceeding, unlike others in which the ERA enunciated a presumption in favor of direct contracting, involves an ongoing project rather than a proposed project. Also, they said, the issue of need for the LNG was determined when the project was authorized in 1972.

The ERA concluded that while it would be inappropriate to use the application for the increased price to modify most aspects of the 1972 approval, the proposed higher import price "does serve to reopen all aspects of the previous orders that deal with the subject of price. . . . ERA agrees with Maryland that the presumption in favor of direct sales contracts is precedential in this proceeding, and that the prehearing order should be amended to require the applicants to demonstrate one of two things: either that the distribution companies served by this project will purchase the gas directly from the applicants, or that there is something about this case which distinguishes it from the precedents established in previous ERA decisions." Accordingly, the ERA directed the applicants to address the presumption in favor of direct sales in their direct case, and to conduct a survey of their customers to determine if they are willing to enter into direct contracts to purchase the regasified LNG on terms and conditions of the contract amendment which is sought to be approved herein.

The ERA also directed the applicants to submit a written report describing an accident at the LNG facilities at Cove Point which killed one worker and seriously injured another and resulted in a shutdown on 10/6/79. 1/ The report must describe the accident in detail and the effect it will have on the ability of the parties to deliver the LNG here involved and the timing of reaching a final decision.

1/ Preliminary findings by the National Transportation Board indicated that the explosion occurred when a worker, seeking to correct a leakage of LNG from a faulty pump seal, opened a circuit breaker. A spark from the circuit breaker ignited the leaking gas vapors. On 9/18/79 the FERC, after holding three days of hearings, approved a limited resumption of service at the facilities subject to certain conditions. (See REPORT NO. 1231, p10.)

FERC Affirms Initial Decision Authorizing Transportation of Gas Purchased by Public Service to Displace Fuel Oil Use; Other Related Developments

On 10/22/79 the FERC affirmed an initial decision issued 7/23/79 by Administrative Law Judge Stephen L. Grossman authorizing Tennessee Gas Pipeline Co. (CP79-304) and Transcontinental Gas Pipe Line Corp. (CP79-312) to transport (through 10/15/79) up to 35,000 Mcf/d of gas purchased by Public Service Electric & Gas Co. from Equitable Gas Co. for displacement of fuel oil in the generation of electricity. These transportation arrangements were the subject of an expedited hearing last July in accordance with procedures established in Order No. 30 (RM79-34) issued 5/17/79. Order No. 30 -- effective through 6/1/80 -- authorizes transportation by interstate pipelines on a "self-implementing" basis of natural gas purchased by "eligible users" from producers, intrastate pipelines and local distributors for fuel oil displacement purposes, but requires Section 7(c) certificates for transportation of gas purchased for such purposes from interstate pipelines in order "to assure that the ability of interstate pipelines to purchase general system supply is not prejudiced in favor of direct purchases."

Public Service contracted to purchase up to a total of 4 Bcf from Equitable Gas through 10/15/79, including 2.5 Bcf on a firm "take-or-pay" basis and the remaining 1.5 Bcf subject to an option (which Public Service decided not to exercise), at a price of $2.25/Mcf. This purchase, which would displace up to 650,000 barrels of oil, represented part of an overall effort by Public Service to buy 24 Bcf of gas to displace 4 million barrels of oil over a one-year period. Tennessee proposed to transport the gas by displacement either to an existing point of delivery to Public Service or to an existing interconnection with Transco, for further delivery to Public Service. Tennessee and Transco were issued temporary certificates on 6/29/79, and deliveries commenced 7/13/79.

Judge Grossman reviewed the three questions set forth in Order No. 30 for consideration: (1) whether any other natural gas company seeks to purchase the gas proposed to be transported for system supply; (2) the price charged and revenues retained by the seller; and (3) disposition of the natural gas in the event that certification is not granted. In the case at hand, the Law Judge noted that no other natural gas company sought to purchase the subject gas for its own system. Second, the gas had a low direct cost to Equitable (20¢/Mcf in some instances) but was priced by Equitable (at $2.25/Mcf) higher than any of its other gas. Equitable proposed to credit its intrastate customers (accounting for 99.8% of its sales) with one-half of the revenues received. The company's single interstate customer, representing an insignificant portion of Equitable's business, will not share in the proceeds. Third, Judge Grossman observed, Equitable has no other market for these volumes. Therefore, if the transaction is not approved, Equitable will cut back its Appalachian area production or purchases, including purchases from interstate pipeline suppliers. Based on this analysis, the Law Judge concluded that the public convenience and necessity test had been met in this case. Interstate system supply will not be threatened, jurisdictional ratepayers will not be disadvantaged, and there is no reason to treat the interstate pipeline supplier here in any different manner from intrastate suppliers. He accordingly recommended certification on condition that the approved transportation service be subject to interruption prior to interruption of firm and other interruptible sales and services. (See REPORT NO. 1219, pp8-9.)

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To date, only two other hearings have been held in the Commission involving transportation of gas purchased for fuel oil displacement purposes. These involved

applications by (1) Transcontinental Gas Pipe Line Corp. (CP79-228) to transport for two years up to 100,000 MMBtu/d purchased by Consolidated Edison Co. of New York from Consolidated Gas supply Corp. in Louisiana at an initial price of $1.89/MMBtu through 6/30/79, plus 7¢ escalations each six months thereafter up to $2.17/MMBtu; and (2) Transco (CP79-214, CP79-275), National Fuel Supply Corp. (CP79-221), Tennessee Gas Pipeline Co. (CP79-260) and Texas Eastern Transmission Corp. (CP79-278) to transport up to 75,000 dekatherms per day purchased by ConEd from National Fuel Distribution Corp. at $2.00/dekatherm, subject to adjustment. The FERC conditionally approved these transportation applications in orders issued 8/13/79. 1/ Among other things, the Commission concluded that both ConGas and National Distribution had surplus gas avilable -- largely because of self-help efforts -- and would probably have only limited success in disposing of this surplus without the sales to ConEd. In each case, the Commission further concluded that the surplus was not likely to become available for interstate markets. For example, the Commission noted, ConGas had already reduced its takes of gas and, without a means of eliminating surplus supply, could be forced to cut takes further, which could cause take-or-pay penalties. (See REPORT NO. 1222, pp12-15.)

In the case of ConEd's purchase from National Distribution, a portion of National Distribution's surplus stems from a 1972 contract with Ashland Oil, Inc. for the purchae of SNG. Last July the New York PSC denied a request by National Distribution to amend the 1972 contract so as to reduce daily takes in both winter and summer months and to pay Ashland $1.00/Mcf for any gas not accepted. The PSC instead directed National Distribution to cease all further purchases of SNG from Ashland effective 9/5/79 on the ground that the supply was not needed to meet customer needs and was too high in price, and to pay only 50¢/Mcf for gas not accepted. However, National Distribution was given an opportunity to propose an alternative means to reduce the cost of its SNG purchases.

Recently, on 10/2/79, the New York PSC rejected a revised supplemental agreement covering SNG purchases from Ashland. The PSC concluded that there is "no economically sound justification" for continued purchase of SNG at Ashland's price and that National Distribution's ratepayers should not be required to pay $18 million more per year in gas rates for the purpose of maintaining the existing mix of products that flow from Ashland's refinery. The PSC further provided that National Distribution would be permitted to pass through only 50¢/Mcf of Ashland's SNG price in its gas adjustment clause, unless Ashland agreed to sell the at the cost of National Distribution's gas purchased from its pipeline supplier, plus 50¢/Mcf, in which case that amount may be passed through the gas adjustment clause. Ashland's price for SNG is now $5.40/Mcf while National Distribution's average cost of pipeline gas is $2.35/Mcf.

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1/ Recently, on 10/11/79, the Commission denied petitions by Transco for clarification of a condition providing for prorata interruption of transportation service performed pursuant to the 8/13/79 orders and Order No. 30 for fuel oil displacement prior to interruption of any firm or other interruptible services. However, the Commission indicated its intent that transportation services to Order No. 533 industrial buyers of direct sale gas for displacement of fuel oil consumed in low priority uses -- now permitted under an interim rule adopted in Order No. 52 (RM80-1) amending the Order No. 533 program so as to remove end-use restrictions on use of the direct sale gas -- be interrupted on the same basis as transportation certificated under Order No. 30.

Recently, on 10/22/79, the Pennsylvania PUC protested an application by Texas Eastern Transmission Corp. (CP79-488) to transport up to 15,000 dekatherms per day purchased by Consolidated Edison Co. of New York from UGI Corp. for fuel oil displacement in electric and/or steam generation. The PUC objected that UGI Corp. failed to provide for return to its customers of any portion of the gross profit to be received from the proposed sale to ConEd. The proposed sale may also be adverse to the public interest in other respects, the PUC added.

Gas Distributor Groups Seek Initiation of FERC Rulemaking on Distributor-Owned Supplies

On 10/22/79 the General Service Customer Group, an ad hoc group of 12 gas distribution companies serving Illinois, Michigan, Missouri, Indiana and Ohio, filed comments with the FERC supporting an 8/13/79 petition by the Associated Gas Distributors (RM79-71) for initiation of a FERC proposed rulemaking on distributor-owned gas supplies. (Public notice of the petition has never been issued.)

In its petition, AGD stressed the need for a general Commission policy statement with regard to interstate transportation of natural gas supplies obtained by gas distribution companies through their own exploration and development activities. Specifically, the petition seeks Commission approval of distributor requests to require interstate pipelines to provide transportation on a firm, noninterruptible basis of distributor-owned gas to the extent that the transported volumes, when considered together with any other gas supplies available to the distributor from the pipeline, do not exceed the daily volume of gas service to which the distributor is entitled under contracts certificated or approved by the Commission. To the extent that volumes exceeded that contract level, transportation of the excess would be provided on a best efforts basis. No pipeline, however, could be compelled to expand its transportation facilities or provide any service which would impair its ability to render adequate service to its customers. The proposal would also be subject to the emergency allocation authorities of Title III of the NGPA.

Additionally, AGD urged adoption of a "finders-keepers" rule to assure that natural gas volumes resulting from a gas distributor's exploration and development activities would be available to the customers of the given distributor. This rule would not be applicable to any form of wellhead or in-place purchases of gas reserves not associated with E&D efforts of a distributor or its affiliate or subsidiary.

In support of its request, AGD cited increasing exploration and development activities by gas distribution companies owing to their need for supplemental gas supplies and the institutional obstacles to obtaining supplies from sources such as imported LNG or manufactured SNG.

The petition called attention to Section 603 of the OCS Amendments Act of 1978 which specifically mandates the Commission -- after an opportunity for comments -- to promulgate a statement of policy setting forth standards for certificating transportation of natural gas produced from offshore leases owned by local distribution companies to those companies' service areas. This provision, AGD stated, demonstrates Congressional recognition that a "finders-keepers" rule is necessary to encourage participation by local distributors in self-help exploration and development activities in the Federal Domain. Sections 605 and 608 of the Public

FUELS

CON EDISON'S SUPPLIES OF GAS FOR POWER GENERATION COULD BE PINCHED THIS WINTER because the New York Public Service Commission has refused to allow the utility's supplier to continue to purchase expensive synthetic natural gas for sale to its regular customers. Consolidated Edison is buying natural gas for boiler fuel from National Fuel Gas Distribution Corp. on a day-to-day basis at a rate of about 22-billion cubic fect annually. But, according to a National Fuel Gas spokesman, the curtailment of synthetic gas deliveries from Ashland Oil has reduced the gas utility's ability to meet demand in extremely cold weather. A spell of such weather that forced National to dip into its storage to meet demand would bring a halt to the sales to Con Edison, he said.

A spokesman for Ashland, however, said the impact of the PSC's ruling – refusing to permit National to pay $5.40/thousand cubic feet for synthetic gas, while it is able to sell pipeline gas to Con Edison for roughly $2.65/mcf – would have a far greater impact. He said because Ashland no longer had a market for all of the naphtha (feedstock for syngas) produced at its Buffalo, N.Y., refinery, the company would have to reduce the amount of crude oil processed by the facility by 20%, reducing its output of home heating oil and gasoline by a similar fraction. But a spokesman for the PSC said, "While the refinery cutback likely would have a significant effect on the supplies of gasoline in western New York, our people say that it will not likely have that great an effect on the supplies of No. 2 oil."

In a letter to PSC chairman Charles Zielinski, Ashland Oil president Robert Yancey warned the commission of the weight of its decision: "The responsibility for shutting down the SNG [syngas] plant at Buffalo and the consequence of our having to curtail crude runs lies with you and the other commissioners. Western New York could become a disaster area and many homes could go cold with ensuing hardship. Gasoline lines could reappear. This is not a 'threat' as you and the other commissioners have stated, but an operating reality that has been supported by outside experts on such subjects."

In its order denying contract approval to National, the PSC stated that National "does not now need to take any SNG from Ashland to meet the needs of its customers," and further, that "[i]t is also apparent . . . that Ashland is still unwilling to lower its price of SNG to a level more competitive with pipeline gas and that National Fuel is either unwilling or unable to sell the gas at the price being charged by Ashland." Taking up the question of the adequacy of supplies of No. 2 oil and gasoline in western New York, the PSC said it does "not believe it would be proper to require National Fuel's ratepayers to pay $18-million more . . . for the purpose of maintaining the existing mix of products that flow from Ashland's refinery." There is a "very serious question" whether the Public Service law would permit requiring a payment for that purpose, the commission said. National Fuel Gas has petitioned the PSC for reconsideration and a decision is expected this week.

Utility Regulatory Policies Act and Section 311 of the NGPA, AGD added, would also support establishment of the proposed rulemaking and a "finders-keepers" rule. 1/

AGD's petition further stated that any rule applicable to gas distributor exploration and development activity in the offshore area should also apply in the onshore area. Passage of the NGPA and elimination of the dual market system and its concomitant pricing disparities make distinctions between offshore and onshore gas "irrelevant," the petition argued. Expansion of the policy statement required under Section 603 of the OCS Amendments to include onshore as well as offshore gas, AGD added, "would also result in a single, comprehensive rule" confirming Commission support expressed in various cases for the principle of "finders-keepers" for gas distribution companies.

In its comments supporting the AGD petition, the General Service Customer Group noted its reliance on interstate pipelines for transportation of gas reserves which are developed in areas quite distant from their respective service areas. Access to potential gas reserves for exploration and development purposes would be foreclosed as a possibility if transportation service were unavailable, the group noted.

* * * * *

In another development related to distributor exploration and development activities, Public Service Electric & Gas Co. (CP79-483) filed on 10/1/79 a request for a declaratory order with regard to transportation service for gas supplies ~~developed through~~ purchased from its wholly-owned subsidiary, Energy Development Corp. PSE&G stated that the transportation certificates ~~governing the service~~ covering this gas are presently conditioned to require that gas transported may not be used as boiler fuel for electric generation unless such supplies are first offered for sale to one of the three transporting pipelines (Texas Gas Transmission, Tennessee and Transco). In light of the recent DOE policy to encourage use of natural gas as boiler fuel for purposes of displacing fuel oil, PSE&G ~~asserted that~~ said it is unsure whether purchases of natural gas which it is presently considering for such displacement purposes would fall within the purview of the restrictions set forth in the existing transportation certificates. Accordingly, PSE&G requested a declaratory order that the use of natural gas as boiler fuel for displacement would not violate the transmission conditions contained in the certificates for transportation of its subsidiary's gas or, in the alternative, that the conditions be suspended for the duration of the displacement transactions contemplated by the company. (See Report No. 1232, p35.)

1/ Section 605 of PURPA protects entitlements to any conserved volumes of natural gas in the event of revision of a curtailment plan; Section 608 of PURPA provides FERC with authority to certificate transportation service for high priority uses and has been cited by FERC as a statutory basis for its Order No. 2 program. Section 311 of the NGPA permits FERC to authorize interstate pipeline transportation on behalf of local distribution companies.

FERC Continues to Monitor Emergency Purchases by Interstate Pipeline Companies

The Office of Pipeline and Producer Regulation (OPPR) of FERC recently issued another monitoring report summarizing information on emergency purchases by natural gas pipelines and distributors. These reports cover (1) 60-day emergency purchases (authorized under Section 157 of the Commission's Regulations under the Natural Gas Act); (2) sales for up to two years by intrastate pipelines to interstate pipelines or distribution companies (Section 311(b) of the NGPA); (3) assignments of contractual rights to receive surplus gas for up to two years by intrastate pipelines to interstate pipelines or distribution companies (Section 312 of the NGPA); (4) emergency transportation of gas by interstate pipelines for others (authorized by Section 311(a)) including, among others, transport of gas purchased directly by end-use customers (self-help gas) and gas transported under the fuel oil displacement program. All four of these categories are termed "emergency gas" in the monitoring reports.

The monitoring reports are compiled by OPPR every two weeks on the basis of telephone surveys of 29 major interstate pipeline companies. Each survey covers actual volumes purchased for one week and projected volumes to be purchased during the second week. Thirteen bi-weekly monitoring reports have been issued by Staff since the beginning of April. The coverage below -- an update of information summarized in REPORT NO. 1224, pp21-25 -- pertains to actual deliveries during the weeks ended 8/25, 9/8 and 9/22/79. In each of these weeks, average deliveries averaged over 1 Bcf/d.

Six of the 29 reporting pipelines made purchases of emergency gas from intrastate pipeline companies or local distribution companies during the six-week time period analyzed. The largest volumes were purchased by United Gas Pipe Line Co., Transwestern Pipeline Co. and Texas Eastern Transmission Corp.

Total Emergency Purchases by Interstate Pipelines from Intrastate Pipelines and Local Distribution Companies

	Week Ending					
	8/25/79		9/8/79		9/22/79	
	Average Mcf/d	% of Total	Average Mcf/d	% of Total	Average Mcf/d	% of Total
United Gas Pipe Line Co.	385,580	44.5%	315,315	37.2%	324,829	36.8%
Transwestern Pipeline Co.	239,000	27.6	347,000	40.9	314,000	35.7
Texas Eastern Transmission Corp.	159,000	18.4	105,000	12.5	150,000	17.0
Texas Gas Transmission Corp.	43,000	4.9	40,219	4.7	42,041	4.8
Transcontinental Gas Pipe Line Corp.	20,000	2.3	20,000	2.3	20,000	2.3
Florida Gas Transmission Corp.	20,000	2.3	20,000	2.3	30,000	3.4
Total	866,580	100.0%	848,234	100.0%	880,870	100.0%

Purchases under Section 311(b), which cover sales by intrastate pipeline companies or distribution companies to interstate pipelines or distribution companies, account for the largest volumes of emergency sales. Total purchases by pipelines and by distribution companies in this category, as well as the percent of Section 311(b) purchases to total monitored purchases, were as follows:

Section 311(b) Purchases	Week Ending 8/25/79 Average Mcf/d	% of Total	9/8/79 Average Mcf/d	% of Total	9/22/79 Average Mcf/d	% of Total
Pipeline Purchases	598,483	55.0%	656,891	64.5%	663,766	63.1%
Distributor Purchases	106,467	9.8	97,591	9.6	106,589	10.1
Total Section 311(b) Purchases	704,950	64.8	754,482	74.1	770,355	73.2
Total Purchases	1,087,867		1,017,995		1,052,181	

Two pipeline companies, and no distributors, have acquired gas by means of Section 312, which permits assignments for two years of contractual rights from an intrastate pipeline to an interstate pipeline company.

Purchases were made under 60-day emergency sales by interstate pipelines only during the two-week period ending 9/1/79. Since that time, purchases have been made under the provisions of Sections 311 and 312 of the NGPA, which authorize sales for periods up to two years.

In contrast, 60-day emergency sales account for 52% of the total purchases by distributors for the week ending 8/25/79, 42% for the week ending 9/8/79, and 41% for the week ending 9/22/79 (see accompanying table for details).

The major intrastate suppliers of emergency gas are Delhi Gas Pipeline, Houston Pipeline Co. and Lo-Vaca Gas Gathering Co., which accounted for 59.2% of the total sales for the week ending 8/25/79, 66.3% for the week ending 9/1/79, and 67.3% for the week ending 9/22/79.

The following table summarizes intrastate pipeline sales by major supplier:

Sales by:	Week Ending 8/25/79 Average Mcf/d	% of Total	9/8/79 Average Mcf/d	% of Total	9/22/79 Average Mcf/d	% of Total
Delhi Gas Pipe Line Co.						
To pipelines	189,883		174,264		199,518	
To distributors	138,724		135,044		108,320	
Total	328,607	30.2%	309,308	30.4%	307,838	29.3%
Houston Pipeline Co. (to pipelines only)	222,857	20.5	200,221	19.7	245,914	23.4
Lo-Vaca Gas Gathering Co. (to pipelines only)	93,000	8.5	165,000	16.2	154,000	14.6
Total, Three Suppliers	644,464	59.2	674,529	66.3	707,752	67.3
Total Supply	1,087,867		1,017,995		1,052,181	

Pricing information is available beginning with the week ending 9/8/79. For sales to interstate pipeline companies, prices ranged from a low of $1.79/Mcf for a sale by Southwest Gas to United Gas Pipe Line to a high of $2.50/Mcf for a sale by Louisiana Resources to Florida Gas Transmission. For sales to distributors, the range is from $1.71 charged by Delhi for gas produced from the Cameron area of Texas up to $2.68 for gas sold by National Fuel Gas. The average price for all

sales to pipelines was approximately $2.18/Mcf for the week ending 9/8/79 and $2.20 for the week ending 9/22/79. The average price to distributors was $2.16 for the week ending 9/8/79 (data not available for 9/22/79).

The accompanying table summarizes the actual purchases for the weeks ending 8/25, 9/8 and 9/22/79. The first part shows the emergency purchases made by interstate pipeline companies from intrastate pipeline companies; the second part sets out the emergency purchases by distributors from intrastate pipelines as reported by the transporting pipeline. Available price data for the weeks ending 9/8 and 9/22 are included in the table.

Emergency Purchases by Interstate Pipeline Companies from Intrastate Pipeline Companies and Local Distribution Companies

	Week Ending				
	8/25/79	9/8/79		9/22/79	
Interstate Pipeline Purchases	Average Mcf/d	Average Price ($/Mcf)	Average Mcf/d	Average Price ($/Mcf)	Average Mcf/d
60-Day Emergency Sales (Section 157)					
Texas Gas Transmission Corp.	41,000	—	—	—	—
United Gas Pipe Line Co.	20,000	—	—	—	-
Total	61,000	—	—	—	-
Purchases of Surplus Gas (Section 284(311(b)))					
Florida Gas Transmission Co.	20,000	$2.50	20,000	$2.50	30,000
Texas Eastern Transmission Corp.	159,000	2.21	105,700	2.23	150,000
Texas Gas Transmission Corp.	2,000	2.29	40,219	2.27	42,041
Transcontinental Gas Pipe Line Corp.	20,000	2.06	20,000	2.06	20,000
Transwestern Pipeline Co.	164,000	2.16	272,000	2.19	239,000
United Gas Pipe Line Co.	233,483	2.14	198,972	2.14	182,725
Total	598,483	2.18	656,891	2.20	663,766
Purchases by Assignment (Section 284.312)					
Transwestern Pipeline Co.	75,000	2.09	75,000	2.13	75,000
United Gas Pipe Line Co.	132,097	2.21	116,343	2.21	142,104
Total	207,097	2.16	191,343	2.18	217,104
Total Emergency Purchases by Interstate Pipelines	866,580	2.18	848,234	2.20	880,870
Distributor Purchases					
60-Day Emergency Sales (Section 157)	114,472	2.50	72,170	NA	69,722
Purchases of Surplus Gas (Section 284(311(b)))	106,467	1.91	97,591	1.91	106,589
Total Emergency Purchases by Distributor Companies	220,939	2.16	169,761	NA	171,311
Total Emergency Purchases by Pipelines and Distributor Companies	1,087,867	2.18	1,017,995	NA	1,052,181
Transportation of Gas for Others (Section 311(a))					
Total	303,867	—	209,099	—	333,277

Source: FERC Staff bi-weekly monitoring reports of emergency purchases made by interstate pipeline companies and distributor companies from intrastate pipeline companies.

Texas Eastern Seeks Advance Approval for Rate Treatment of R&D Costs for Project to Produce Natural Gas from Coal Seams

On 10/4/79 the FERC issued notice of a petition filed on 9/21/79 by Texas Eastern Transmission Corp. (RP79-81) seeking advance approval for rate treatment of research, development and demonstration costs relating to its proposed participation -- together with PSE&G Research Corp., Texas Energy Services, Inc. and Sun Gas Co. -- in an R&D project for the production of natural gas from coal seams located in Tuscaloosa County, Alabama. The total project cost is estimated at $13,937,000, of which about $3,484,000 represents the total capital investment requirement for Texas Eastern as one of the four participants. Texas Eastern seeks advance approval for accounting and rate treatment for these R&D expenditures pursuant to Order No. 566 (RM76-17), which prescribes guidelines and procedures for such treatment by natural gas pipelines and electric utilities, and by research organizations supported by several jurisdictional companies.

In its petition, Texas Eastern explained that in 1976 it participated in a study with INTERCOMP Resource Development & Engineering, Inc. on the feasibility of producing methane from coal seams. That study, Texas Eastern said, concluded that gas resources trapped in coal seams exceed hundreds of trillion cubic feet and that production rates from some of the seams could be obtained that would result in economically attractive projects. Subsequently, INTERCOMP submitted a plan for a project to develop and demonstrate in commercial quantities the production of gas from coal seams in Tuscaloosa County. Texas Eastern decided to participate in the project -- to be known as the Tuscol project -- which will be divided into three phases and take four years to complete. INTERCOMP will manage the entire project and act as operator through completion of Phase II when it may relinquish such duties (except planning, managing and engineering) to a designated operator.

More specifically, Phase I will include (1) lease acquisitions in the Warrior Basin, Tuscaloosa County; (2) collection and evaluation of data on the area; (3) selection of a site where the depth of the coal beds is representative of those in the area; (4) preparation of a complete and detailed design of the test wells; and (5) obtaining necessary permits, including water disposal permits. Phase II will involve the drilling of four test wells, principally to determine which coal seams will contribute significantly to the production of gas and which should therefore be developed. If sustained production rates from all four wells indicate that development of the project should continue into Phase III, a well module design will be developed. Also, prior to commencement of Phase III, all land acquisitions will be completed and all gas purchase and sales agreements finalized. Phase III will involve the drilling and completion of about 92 additional wells to demonstrate the commercial feasibility of gas production from coal seams. A testing and monitoring program will also be developed to determine whether the project is achieving design specifications.

Texas Eastern noted that the DOE has recently undertaken a program to demonstrate the feasibility of recovering commercial quantities of methane from virgin coal beds -- which objective has not yet been achieved. While the Tuscol project will differ in numerous respects from this DOE program, developments will be monitored in order to ensure that its project does not overlap or duplicate that or any other existing R&D project or program. Also, as a member of the Gas Research Institute, Texas Eastern will be kept informed on GRI and gas industry efforts in this area.

In support of the project, Texas Eastern noted that its estimated reserve life has diminished in the past decade from 16.7 years in 1967 to 8.1 years in 1978. Also, its projected level of curtailment for the 1979 summer and the 1979-1980 winter periods, respectively, represent systemwide aggregate curtailments of 0.303 and 49.06% of Priority 2 uses. As percentage of annual system requirements, these curtailments represent aggregates of 19.33% and 15.03%, respectively, for these two periods. Although the pipeline's gas shortage has been somewhat alleviated by recent availability of surplus supplies from the intrastate market, "this situation is temporary only. Texas Eastern does not believe that it can rely on the continued availability of such surplus, nor on the continued availability of emergency gas, for long-term gas supply requirements. Establishing new gaseous energy sources is critically important to alleviating the nation's shortage of gas; the development of these new gaseous energy sources require expanded research, development and demonstration . . . efforts in the area of supplemental and alternative fuel gases."

U.S. Supreme Court Denies Review of Lower Court Decisions Involving Abandonment, Curtailment and Contract Interpretation Questions

On 10/1/79 the U.S. Supreme Court denied petitions for certiorari with respect to the following decisions:

(1) A Fifth Circuit decision of 1/11/79 affirming an FPC ruling (issued on 4/26/77) that the State of Texas (or its agency) and Superior Oil Co. must obtain abandonment authorization under Section 7(b) before royalty gas which the School Land Board of Texas elected to take in-kind and contracted to sell directly to Public Service Co. of North Carolina (RP76-103) may be withdrawn from sale by Superior in interstate commerce to Natural Gas Pipeline Co. of America. State of Louisiana v. FERC, Nos. 78-1585 et al.

The royalty gas here involved is produced by Superior from three state leases in the High Island Field, offshore Texas and has been sold to Natural since 1971. In 1974 the unit agreement covering these leases was revised to permit Texas to take its royalty gas in-kind, and Superior's certificate was subsequently amended to recognize this right (but not to authorize Superior to divert dedicated gas from the interstate market without abandonment authorization). The School Land Board of Texas thereafter contracted to sell royalty gas to Public Service (a distributor customer of Transcontinental Gas Pipe Line Corp.) over a limited period at a rate of $1.44/Mcf. Transco, however, refused to transport the gas without a Commission ruling that abandonment authority was not necessary. Accordingly, Public Service petitioned for a declaratory order that the FPC lacked jurisdiction to require abandonment authorization in this case. The petition contended that since neither the State of Texas nor the School Land Board of Texas was a natural gas company as defined by the Natural Gas Act, there was no impediment under Section 7(b) of the Act or otherwise to preclude the sale and transportation of the royalty gas to Public Service.

In its declaratory order issued 4/26/77, the FPC agreed that neither a state nor a state agency is a jurisdictional natural gas company, but noted that the reserves covered by at least two of the three leases were dedicated to interstate commerce when Superior commenced sales to Natural in 1971 pursuant to an FPC certificate. "Once dedicated, the reserves remained dedicated." The FPC thus concluded that, since gas from the two leases became encumbered with the obligations of interstate dedication, that gas could not be withdrawn from interstate sale without Commission authority.

In affirming the Commission, the Fifth Circuit primarily relied on the Supreme Court's Southland Royalty decision (436 U.S. 519) holding that dedication of gas to the interstate market creates a continuing obligation to provide service unless abandonment approval is obtained, and that this obligation to serve attaches to the gas itself. The Fifth Circuit said Southland Royalty established the principle that any party -- whether or not a "natural gas company" -- acquiescing in the "dedication" of its gas to interstate commerce becomes obligated to continue the dedicated service or seek Commission approval to abandon. Thus, the Court declared, the fact that Texas can never become a "natural gas company" is irrelevant once Texas has allowed its gas to be dedicated to interstate service. The Fifth Circuit also rejected petitioners' contention that the Commission's attempt to regulate state-owned gas amounted to an unconstitutional intrusion on state sovereignty. The business engaged in by Texas here, the Court stated, "is an operation indistinguishable from like commercial activities of private business. It is precisely this sort of state activity that may be subject to federal regulation." (See REPORT NOS. 1080, pp4-12; 1102, pp18-21; 1176, App. pp9-10; 1193, pp24-25.)

(2) A Fifth Circuit decision of 3/20/70 affirming FPC Opinion Nos. 807 and 807-A which -- in response to a complaint by Lehigh Portland Cement Co. (RP75-79), a direct interruptible customer of Florida Gas Transmission Co. -- held that FGT's existing curtailment plan was unreasonable and unduly discriminatory because of preference accorded to indirect over direct interruptible customers with similar end uses, and ordered proceedings to develop a new curtailment plan providing equal treatment to direct and indirect customers. Sebring Utilities Commission v. FERC, No. 78-1878.

In addition to upholding Opinion Nos. 807 and 807-A (issued 6/24/77 and 9/22/77, respectively), the Fifth Circuit also affirmed FPC dismissal of a petition and complaint by Fort Pierce Utility Authority of the City of Fort Pierce, Florida and seven other Florida cities (CP77-147) asking the Commission to order curtailment of transportation gas on FGT's system and to require, as a condition of continued transportation, prorata curtailment of transportation contract volumes along with volumes to which direct preferred interruptible customers would otherwise be entitled. (See REPORT NO. 1204, pp25-28.)

(3) Louisiana state court decisions holding that royalty payments by Arkansas Louisiana ~~Gas Co.~~ (RI76-28) to the U.S. Government for gas produced in the Sligo Field, ~~Bossier Parish, Louisiana~~ triggered a favored nation clause in a 1952 contract with Frank J. Hall et al., a group of independent producers. Arkansas Louisiana Gas Co. v. Frank J. Hall, Nos. 78-986 et al.

In 1977, a Louisiana district court held for the Hall group in a breach of contract suit and awarded substantial damages. On appeal, the Second Circuit Court of Appeals of Louisiana affirmed the trial court in regard to activation of the favored nation clause by the royalty payments in question, but remanded the case for a recalculation of damages. Subsequently, the Supreme Court of Louisiana denied Arkla's petition for review. 1/

1/ The Louisiana Supreme Court granted a related petition for certiorari filed by the Hall group for the limited purpose of considering the level of damages. On 3/5/79 the Louisiana Supreme Court approved damages for the period 1961 to 1972 on the basis of the trial court's award (rejected by the state court of appeals).

During the pendency of the litigation in the Louisiana state courts, Arkla petitioned the FPC for a declaratory order that the favored nation clause in its contract with ~~Frank J.~~ Hall ~~et al.~~ was not triggered by royalty payments to the U.S. Government because Arkla did not "purchase" gas from another producer in the Sligo Field at a higher price. The Commission denied this petition on 3/8/76 because of its "policy to defer action on contract questions presented to it involving jurisdictional sales which are pending in court." Arkla appealed this ruling to the D.C. Circuit which, on 5/25/78, granted the Commission's motion for remand of the record. The FERC subsequently requested briefs directed to whether it had primary jurisdiction over the above matter and, if so, whether it should exercise such jurisdiction in the circumstances of this case. ~~(See REPORT NOS. 1043, pp15-16, 1169, pp19-20.)~~ P Remanding after further consid. on remand

~~More recently,~~ on 5/18/79, ~~the FERC~~ reaffirmed the Commission's earlier determination not to exercise jurisdiction over the matter here involved, but ~~noted its~~ disagreement with prior Commission policy of "automatic" deferral to state courts of contract questions pending therein. Rather, the FERC declared, Commission assertion of jurisdiction over contractual issues otherwise litigable in state courts should depend on (1) whether the Commission possesses some special expertise which makes the case peculiarly appropriate for Commission decision; (2) whether there is a need for uniformity of interpretation of the type of question raised by the dispute; and (3) whether the case is important in relation to the regulatory responsibilities of the Commission. In the case at hand, the FERC found no issue involving its special expertise, no need -- or even possibility -- for uniform interpretation of all favored nation clauses, and no major impact on its regulatory responsibilities. In this last connection the FERC noted that the Hall group made no claim for damages higher than the applicable area ceiling rates and that the damages awarded by the Louisiana courts presumably would not exceed these ceilings.

Tenth Circuit Dismisses General Motors' Appeal from FERC Orders Regarding Load Growth on Cities Services' System as Not Ripe for Judicial Review

On 10/11/79 the U.S. Court of Appeals for the Tenth Circuit dismissed a petition by General Motors Corp. for review of FPC orders issued 12/12/77 and 2/8/78 in the Cities Service Gas Co. curtailment proceeding (RP75-62) with respect to load growth. In a clarification of certain prior orders, the 12/12/77 order asserted that any restrictions on load growth imposed in the future after further hearings would be applied prospectively only. The Commission denied rehearing on 2/8/78. The Tenth Circuit held that the challenged orders did not decide the growth restriction question and hence did not constitute a final action for purposes of judicial review. General Motors Corp. v. FERC, No. 78-1101.

The orders under review were an outgrowth of FPC Opinion No. 805 (issued 6/14/77) which prescribed a permanent curtailment plan for Cities and, among other things, required termination of load growth on the pipeline's system effective 1/1/78. To implement the curtailment plan, the Commission directed Cities to establish an Index of Requirements effective 1/1/78 based on customer end-use profiles for loads attached on that date, with an appropriate adjustment for weather conditions. The Commission said this approach would end growth based on gas transported by Cities, but would still permit distributors to serve new customers from volumes resulting from conservation measures, attrition among customers, peak shaving, etc. Cities subsequently sought relief from compliance with the Opinion No. 805 load growth restriction because of sufficient supply to permit continued growth in high priority requirements. In Opinion No. 805-A issued 8/2/77, the Commission reopened the proceeding for further evidence on the load growth question and,

pending a decision, postponed the 1/1/78 effective date for implementing the Index of Requirements. However, in a 9/30/77 order denying rehearing, the Commission directed Cities to file an Index of Requirements as of 1/1/78 for informational purposes and "warned" that, pending a final decision, any load additions by Cities' distributor customers after 1/1/78 would be at their own risk.

Thereafter, because of uncertainties created for the residential construction industry by the "warning" in the 9/30/77 order, the Commission sua sponte issued a further order on 12/12/77 clarifying that any index of requirements imposed on Cities' system would not be based on connections as of 1/1/78 but instead would be applied prospectively only. Referring to testimony in a U.S. District Court proceeding, the Commission said the economic consequences of a moratorium on residential construction in Cities' service area during the approximately one-year period needed to reach a load growth decision could be substantial. Thus, the FERC declared, "overriding considerations" indicate a need to revise the admonition in prior orders to Cities' distribution companies. (See REPORT NOS. 1110, pp24-26; 1135, pp25-26.)

General Motors objected to the shift reflected in the 12/12/77 order -- which had the effect of permitting Cities to add customers (presumably higher in priority than General Motors) pending resolution of the index of requirements matter -- from a possible index based on 1/1/78 conditions to a possible index based on conditions at some prospective time in the future. General Motors further objected to issuance of the order sua sponte without additional hearings or additions to the record.

The Tenth Circuit concluded that the challenged orders must be viewed in the context of an ongoing proceeding and hence are not ripe for judicial review. While General Motors' core objection to the change from a January 1 date to a prospective date for application of any requirements index relates to a specific matter, the Court stated, this change is "in the context of ongoing consideration of the many facts of the curtailment plan." Further, the Court asserted, the Commission had the authority to make the change sua sponte on the basis of the existing record without a petition requesting action. "The Commission has a continuing duty to consider the consequences of actions it has taken in ongoing proceedings, and to make adjustments it considers to be in the public interest. The original record contained adequate data to support the Commission's change in the dates."

The Tenth Circuit decision was handed down by Chief Judge Seth, who was joined by Judge Breitenstein. The third member of the panel (Judge McKay) dissented on the ground that the challenged orders -- which had the effect of encouraging or permitting substantial new gas user connections in times of recurring gas supply shortages -- could not be "realistically assessed" as imposing no final or irrevocable damage to customers placed in an allocation position inferior to the new hookups.

FERC Names Ray A. Huber as Acting Director of Public Information Division

On 10/23/79 Kenneth S. Levine, Director of the FERC Office of Congressional and Public Affairs, announced the appointment of Ray A. Huber as Acting Director of the Commission's Division of Public Information. Mr. Huber joined the Office of Congressional and Public Affairs in May of 1979 and has served successively as congressional liaison officer, public information specialist and consumer affairs consultant.

Previously, Mr. Huber served from 1966 through 1978 as Administrative Assistant to Congressman Fred B. Rooney of Pennsylvania, directing public and press relations and legislative activities. For several years prior to 1966, Mr. Huber was a reporter for the Globe-Times newspaper in Bethlehem, Pennsylvania, and won a series of Pennsylvania Newspaper Publishers Association awards for government news writing, investigative reporting and political commentary.

The Division of Public Information is one of three divisions in the recently organized Office of Congressional and Public Affairs. The other two divisions are Congressional Relations and Consumer Affairs.

FERC Discontinues 15 Data Collection Forms; Elimination of Five Additional Forms Proposed

On 10/23/79 the FERC issued Order No. 53 (RM79-38) adopting a proposal to discontinue use of 15 data collection forms no longer needed by the Commission to carry out its regulatory responsibilities.

Only three of the 15 forms to be discontinued relate to natural gas: (1) Form 17 - Monthly Reports of Natural Gas Pipeline Curtailments; (2) Form 45 - Report of New Nonjurisdictional Sales of Natural Gas; and (3) Form 64 - Annual Report of Producer Expenditures, Exploration and Development Activity, Production, Reserve Additions and Revenues. The remaining forms pertain to hydroelectric project costs, electric utility generation, weekly fuel emergency reports, electric service reliability, and municipal utility reporting. (See REPORT NO. 1205, pp35-36.)

Eleven of the forms will be discontinued immediately, while four (involving electric utility reliability, contingency planning and municipal utility reports) will be discontinued on 1/1/80 in order to allow EIA time to obtain OMB approval for continued collection of the data involved.

The following day, on 10/24/79, the FERC proposed to discontinue another five forms -- including Form 40 (Natural Gas Companies' Annual Report of Proved Domestic Reserves). This form has been superseded by Form EIA-23 which requires reporting of domestic oil and gas reserves by operator. The other four forms proposed for elimination relate to electric bills and retail rates.

Further Volume of FPC Reports Available

On 10/18/79 the FERC announced the availability of Volume No. 48 of the Federal Power Commission Reports, containing FPC Opinions, orders, and precedential procedural orders for the period 7/1/72 through 12/31/72.

Copies of the bound volume may be purchased from the Superintendent of Documents, U.S. Government Printing Office, Washington, D.C. 20402. Volume No. 48 is available for $19.50 (GPO Stock No. 061-002-0023-5).