

# REPORT OF THE COMMITTEE ON NATURAL GAS RATE AND ACCOUNTING REGULATIONS

## I. NATURAL GAS POLICY ACT

### A. Title II Incremental Pricing

On May 20, 1980, the U.S. House of Representatives voted overwhelmingly, 396-34, to disapprove the commission's proposal for Phase II incremental pricing under Title II of the NGPA. The Phase II proposal, issued in Order No. 80, Docket No. RM80-10, was developed pursuant to NGPA Section 202, which directed the Commission to submit a plan (subject to veto by either House of Congress), within 18 months of enactment, for expanding the incremental pricing program beyond industrial boiler fuel users to include other industrial facilities.

The Phase II plan proposed by the Commission would have extended incremental pricing to virtually all industrial natural gas users not afforded statutory exemptions. Implementation would have been based on a single alternative fuel price ceiling equal to the price of No. 6 high-sulfur residual fuel oil, with the first 300 Mcf per day for each industrial user exempt from incremental pricing. State authorities would have been given some discretion during the first year to spread some of the surcharge burden among affected industrial users within the state.

Although the commission had the discretion to submit another Phase II plan to Congress for approval, the overwhelming veto by the House indicated that any such proposal probably would be disapproved.

### B. Section 311 Transportation and Sales Arrangements

In *Algonquin Gas Transmission Co.*, Docket No. CP79-234 (May 30, 1980), the Commission granted a request that the transportation service which several pipelines proposed to render for local distribution companies be authorized under NGA § 7(c) rather than under § 311(a)(1) of the NGPA. However, the commission declared that it, rather than the applicant, would determine when to exercise authority under § 311(a)(1) or under § 7(c). The Commission further stated that it could elect to condition any long-term § 311 authorization on service continuity requirements to provide protection similar to the abandonment protection statutorily imposed by NGA § 7(b). The Commission also suggested that § 311 offered more adjustment flexibility and, given the NGPA enforcement provisions, better opportunity for the Commission to insure compliance with the conditions attached to a service authorization. However, in *Algonquin*, the Commission granted the certification under § 7(c) because the gas to be transported was Algerian LNG and the substantial financial commitments involved called for "the greater certainty available under" the NGA.

Under Part 284 of the Commission's regulations, in general an interstate pipeline is permitted to use an existing, Commission-approved transportation rate or methodology to determine the just and reasonable rate for service to be rendered under § 311(a)(1). However, Part 284 requires that all revenues in excess of out-of-pocket expenses received by the pipeline are to be flowed through to the pipeline's jurisdictional customers as a credit to Account 191 (Deferred Purchase

Gas Costs). At the end of 1979, the Court of Appeals for the D.C. Circuit handed down a decision in *Panhandle Eastern Pipe Line Co. v. FERC*, No. 78-1356 (Dec. 20, 1979), holding that the Commission could not condition a § 7(c) transportation certificate with a similar revenue crediting requirement without first making a rate determination under NGA § 4 or § 5. The Commission's declaration in *Algonquin* that it may choose whether to proceed under § 7 or § 311, would appear to raise a question whether the Commission in fact has unfettered authority to impose through NGPA § 311 and Part 284 a revenue crediting condition that it could not impose on a transportation authorization under § 7.

During 1980, the Commission demonstrated some flexibility in granting intrastate pipelines NGPA § 502(c) adjustments to allow use of state-approved rates as the transportation component of Section 311 transactions. The Commission originally interpreted § 284.123(b)(1)(ii) to require that the comparable intrastate rate be (i) a *city-gate* transportation rate, which was (ii) *in fact* cost-of-service based. However, in *Hydrocarbon Transfer, Inc.*, Docket No. SA80-70 (March 21, 1980), the Director of the Office of Producer and Pipeline Regulation (OPPR) permitted the pipeline to base the transportation component of a § 311(b) sale rate on a rate filed with the Texas Railroad Commission for non-city gate transportation to existing industrial customer. Although the intrastate rate had not yet been approved on a cost-of-service basis, it was being subjected to such an analysis by the Texas regulatory authority, and Hydrocarbon Transfer agreed to be bound by that result for the transportation component in its § 311(b) sale. In a similar action, *Delphi Gas Pipeline Corp.*, Docket No. SA80-73 (April 15, 1980), OPRR authorized Delphi to base rates for a § 311(a)(2) service on an intrastate industrial service tariff rate on file with the Texas commission for a portion of its system claimed to be representative of its transportation service. Delphi agreed to be bound by the results of a cost-of-service review to be undertaken by the Railroad Commission. Given the state agency's familiarity with the pipeline, OPRR found that requiring FERC tariff review would result in special hardship and inequity, and thus that "failure to grant an adjustment will produce at least one of the circumstances identified in Section 502(c)." *Accord, Dow Pipeline Co.*, Docket No. SA80-77 (June 12, 1980). However, in *IMC Pipeline Co.*, Docket No. SA80-133 (November 28, 1980), OPRR denied the applicant permission to use a § 311 transportation component an industrial service rate on file with the Louisiana Conservation Commission (LCC). OPRR found that the LCC was not an appropriate state agency under the Part 284 comparability of service test because the LCC, unlike the Louisiana PSC, lacked jurisdiction to make a cost-based review of comparable, city-gate rates, and that there was no certainty that a cost-of-service standard would be reflected in the LCC review of IMC's rates.

## II. BURDEN OF PROOF

The burden facing the Commission in justifying a methodology it proposes in a rate case was judicially reaffirmed during 1980. In *Public Service Commission of New York v. F.E.R.C.*, No. 79-2182 (D.C. Cir. Sept. 24, 1980), the United States Court of Appeals for the District of Columbia Circuit held that the Commission could not order a new cost allocation method in a rate case in which the filing pipeline did not seek to change its historical allocation method, without first

making a determination that the historical method was "unjust, unreasonable, unduly discriminatory, or preferential" under Section 5(a) of the Natural Gas Act. The court overturned Commission Opinion No. 59 (issued Aug. 6, 1979) in which Transcontinental Gas Pipe Line Corporation (Transco) was ordered to replace its zone differential cost allocation with an Mcf-mile method. The zone rate differentials had been embodied in Transco's rate schedules since first devised in a 1962 settlement agreement approved by the Federal Power Commission.

In reversing the Commission, the court relied on its 1979 decision in *Columbia Gas Transmission Corp. v. F.E.R.C.*, 628 F.2d 578, 586 n. 31 (D.C. Cir. 1979), in which it held that the Commission "bears the burden of explaining the reasonableness of any departure from a longstanding practice, and any facts underlying its explanation must be supported by substantial evidence." The *Transco* decision rejected the Commission's contentions that the 1962 Transco differentials were "merely numbers" and that Commission approval of settlements incorporating zone allocations did not constitute a "settled practice". The court held that in a case such as this in which the pipeline had not proposed to change its pre-existing rate structure, the Commission, not the pipeline, had the burden of proof with respect to such changes.

The court also held that the Commission erred in trying to justify the change with the general principle that "distance is the prime determinant of . . . cost," because the question that the Commission was faced with was not whether it should allocate costs according to distance, but whether in the particular circumstances the Mcf-mile method more accurately reflected distance-related costs than did the existing zone differentials. The court also rejected the Commission's argument that zone allocations which were the result of a 1962 compromise rather than of methodical calculation were obviously inaccurate.

### III. COST ALLOCATION

Major court and Commission proceedings in 1980 resulted in significant modifications of ratemaking practices involving cost allocation. Discussed below are certain key developments.

#### *A. Conversion from a Volumetric to a Dekatherm Basis*

In Opinion No. 43, the FERC allowed Transwestern Pipeline Company to allocate costs of transmission on a heat content basis, rather than on the past volumetric basis. Cities Service Gas Company appealed, challenging this new method of cost allocation as it affected certain joint facilities owned by Cities Service and Pacific Lighting Service Company. Cities Service claimed that a volumetric basis was proper in that it best reflects the actual costs of transmission. Noting that the Commission had previously held that Transwestern's transmission costs for the two customers should be allocated without consideration of distance, the Fifth Circuit stated that the key factor determining volumes to be transported is heat content. Consequently, the Fifth Circuit affirmed the Commission's order. *Cities Service Gas Company v. FERC*, No. 79-3393 (5th Cir. August 11, 1980).

### B. Liquids and Liquefiabiles

Numerous questions regarding the allocation of transportation, compression and separation changes were raised in proceedings involving natural gas liquids and liquefiable hydrocarbons.

In numerous certificate dockets, the Commission expressed its concern over the possible ratepayers subsidy that might arise if transportation costs were not allocated to the pipeline or producer owner of the liquids. Consequently, a number of certificate orders issued in 1980 were conditioned on the requirement that the pipeline allocate certain specified transportation costs between the jurisdictional customers and the recipient of the transportation service. Pipelines sought rehearing of these orders claiming that the Commission's method of allocating costs was arbitrary and capricious. At its December 18, 1980 meeting, the Commission voted to issue an order in Docket No. CP78-340, *et al.*, which would reverse the prior orders and require allocation methods to be established in the pending rate proceedings.\*

The issue of allocation to jurisdictional customers of the costs of compressing producer-owned liquefiabiles was addressed in *Mid-Louisiana Gas Company*, Docket No. RP73-43, Initial Decision issued February 29, 1980. In that case, the Presiding Judge ruled that jurisdictional customers were required to bear all compression costs in excess of the 18 C.F.R. § 2.71 minimum rate of 0.02 cents per Mcf-mile. This is the first case discussing the Section 2.71 rate since the issuance of *Mobil Oil Corp. v. FPC*, 482 F.2d 1238 (1973), which reversed and remanded the order setting that rate.

The issue of allocation of costs incurred in separating liquids was raised in two pending rate cases. Following issuance of the Initial Decision in *Natural Gas Pipeline Company*, Docket No. RP78-78 (issued December 20, 1979), parties submitted briefs on exceptions discussing the Judge's ruling that the HIOS separation charge cannot be allocated to jurisdictional customers. The same issue was litigated in *Texas Gas Transmission Corporation*, Docket No. RP78-94, where the Presiding Judge agreed that the producers, rather than the gas customers, should bear the separation costs. Initial Decision issued January 16, 1981.

### C. Rolled-in vs. Incremental Allocation

The issue of the proper allocation of costs where a pipeline operates separate and distinct pipeline systems was raised in two cases. In *Montana-Dakota Utilities Company v. FERC*, No. 79-1915 (8th Cir. August 41, 1980), the court addressed the case where a pipeline operates separate interstate and intrastate pipeline systems. *Montana-Dakota's* attempt to roll-in the costs of its jurisdictional cost of service was rejected by the Commission on the grounds that the interstate customers received insufficient benefit from the intrastate operations. The court reversed holding that the benefit to jurisdictional customers existed in that the intrastate system "meets a need that would otherwise be filled by interstate gas."

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\*Editor's Note—The Commission's Order on Rehearing was issued in *Trunkline Gas Company, et al.*, Docket Nos. CP78-340, *et al.*, on March 4, 1981.

The Commission's opinion in *Consolidated Gas Supply Corporation*, Docket No. RP79-22, Opinion No. 100, issued October 24, 1980, addressed a different issue: whether storage costs on a pipeline with two distinct jurisdictional systems should be rolled-in and assessed against all customers receiving storage service, or should be directly assigned to the actual user. The Initial Decision in this docket rejected a systemwide allocation of storage costs. The Commission reversed, holding that the recipients of storage service benefit from the entire system, even though they do not physically use portions of the systems.

#### D. Zones

Transmission cost allocation methods range from the Mcf-mile and volumetric methods to the zone-gate method. Major decisions issued by the Commission and the courts reflect a dispute over proper methodology.

In Opinion No. 83, *Southern Natural Gas Company*, Docket No. RP78-36, issued March 27, 1980, the Commission held that introduction of LNG downstream from traditional supply points justified the phased elimination of rate zones on the Southern system and substitution of a volumetric method. The rationale for this systemwide allocation was the same as that raised in the preceding section—all of the customers benefit from the entire system facilities and supplies. In reaching this decision, the Commission stated that Southern's original Mcf-mile proposal was unreasonable in that the assumed physical flows do not reflect the substantive changes in flows that are anticipated.

An earlier Commission decision to change the cost allocation on the Transcontinental Gas Pipe Line system from a zone method to an Mcf-mile method was reversed in *Public Service Commission of the State of New York v. FERC*, No. 79-2182 (D.C. Cir. September 24, 1980). The Court stated that because the pipeline had not proposed the change in allocation methodology, the Commission may not establish a new method unless it first makes a finding under Section 5(a) of the Natural Gas Act that the existing method is unjust and unreasonable. The court held that because the Commission had made no finding that "the Mcf-mile method did a better job of accurately reflecting those distance-related costs than did the existing zone differentials," its order must be reversed.

#### IV. COST CLASSIFICATION

The remanded proceedings in *Cities Service Gas Co.*, Docket No. 74-4, *Texas Gas Transmission Co.*, Docket No. RP75-19, and *Texas Eastern Transmission Co.*, Docket No. RP74-41, reached the briefing stage during the latter portion of 1980. In each case, the company argued that its current situation dictates the utilization of the *Seaboard* formula for cost classification, allocation and rate design. Staff, for slightly different reasons in each case, maintained that a system analysis justifies volumetric cost allocation and rate design. Instead of advocating a purely volumetric approach, however, Staff recommended utilization of the Commission's *United* formula, tantamount to a split between the *Seaboard* and volumetric methodologies. Under this formulation, seventy-five percent of fixed costs are classified to the commodity component and allocated on a volumetric basis, and the remaining twenty-five percent are allocated according to peak usage.

The Staff position was premised on the observation that none of the systems experienced full peak-day utilization, thus making the *Seaboard* approach unjustifiable. Staff argued that, on each system, costs over the last five to ten years for gas plant expansions were not incurred to expand pipeline networks, as was the case during the *Seaboard* era. Such expenditures in recent years were related to additions and replacements of gas supply. Staff asserted that because of the supply-related nature of these costs, the volumetric methodology for cost allocation and rate design should be followed. Initial decisions in the three cases are expected in 1981.

## V. COST OF SERVICE (EXCEPT TAXES)

### A. Advertising and Charitable Contribution Expenses

In *Algonquin Gas Transmission Co.*, Docket No. RP80-72, a proceeding which involves a suspended proposed rate increase and currently awaits an Initial Decision by Administrative Law Judge Brenda P. Murray, Algonquin Gas Transmission Company (Algonquin) seeks to include \$234,046 of "advertising" expenses, comprising both the promotional cost of advertising for sales of gas appliances and also the cost of contributing to the American Gas Association (AGA), as an item in its operating and maintenance (O & M) expenses. Algonquin's treatment of these advertising expenses raised an issue of first impression before the Commission—whether a natural gas company may include in its customer rates (as customer-beneficial expenses) the costs incurred in advertising the general sales of gas appliances where that company does not possess a distribution function that ultimately sells those appliances.

On initial brief, Staff argues that the primary purpose of this particular Algonquin advertising is not conservation-oriented but rather sales-oriented and, as such, allegedly is not beneficial to the ratepayers. Thus, Staff would exclude all advertising expenses from the Company's cost of service treatment, except for \$28,629 which comprised the billboard portion of the "advertising" expenses (apparently to the extent that these particular advertisements do provide some so-called "glib phrases" promoting energy conservation) and the total charitable contribution expenses for AGA dues.

In opposition, Algonquin and the intervenors who addressed this issue contend that the Company incurred these contested expenses in promoting the sales of "energy-efficient" appliances. These "educational" promotions, they argue, acquaint customers with energy conservation-oriented appliances and, as such, are both customer-beneficial and consistent with the national energy purposes of the NGPA and National Energy Conservation Policy Act (42 U.S.C. §§ 300 *et seq.* (1978)). As a result, they reason that the associated costs require cost of service treatment. Bolstering this conclusion, one intervenor, the Algonquin Customer Group, noted in its initial brief, by analogy, that the Department of Energy's Economic Regulatory Administration, under the Public Utility Regulatory Policies Act, published a "Voluntary Guideline" in the *Federal Register* on November 18, 1980, expressly encouraging electric utilities to develop advertisements which promote the use of energy-efficient appliances.

### *B. Research, Demonstration and Development Expenses*

In the area of qualifying Research, Demonstration and Development expenses, defined in Order No. 566 and codified at 18 C.F.R. § 154.38(d)(5)(iii), the FERC and the district of Columbia Circuit recently have addressed significant natural gas cost-of-service issues involving the treatment of: (1) funding unit surcharges on funding services, (2) debt/equity guarantees and financing surcharges on the construction of non-jurisdictional facilities, and (3) unsuccessful project costs.

#### 1. Funding Unit Surcharges

On September 30, 1980, the FERC, in *Gas Research Institute*, Docket No. RP80-108, Opinion No. 96, granted, with minor modifications, an application by the Gas Research Institute (GRI) for advanced approval of its 1981 gas research and development (R&D) program and related 1981-1985 five-year R&D plan, both of which would increase GRI's emphasis upon efficient gas utilization technologies. Of the proposed \$80.5 million 1981 budget submitted to the FERC for approval, approximately \$70.4 million would constitute a funding unit (of 6.1 mills per Mcf) surcharge on the sale and transportation by GRI members of 1981 funding services of 11,571 Bcf of natural gas to distributors for resale, non-member pipelines of GRI and ultimate consumers. Also, of the identical proposed total budget, approximately \$10.1 million would comprise revenues from patent licenses, interest income, contract settlements, and sales of research equipment and unexpended funds collected pursuant to prior approved programs. With a slight modification to a Staff recommendation, GRI then reduced its proposed surcharge on its funding service to approximately \$64.8 million (or 5.6 mills per Mcf) to reflect R&D program money previously received by GRI, never spent and consequently retained in separate accounts.

In approving the overall program and plan, the FERC held this revised funding services requirement to be both just and reasonable and collectable by GRI's jurisdictional members. Further, the FERC required GRI to include the full 50 percent of its members' intrastate volumes in its funding services calculation. Finally, the FERC mandated that a GRI jurisdictional member only could collect the surcharge if it previously had filed an R&D cost adjustment clause complying with 18 C.F.R. § 154.38(d)(5)(v) and containing a provision which provides that this clause is applicable solely to surcharge payments to GRI. Remittance of these payments must result within 30 days of receipt of the particular funding services and from the individual receiving those services.

#### 2. Debt/Equity Guarantees and Financing Surcharges

On December 8, 1980, the District of Columbia Circuit in *Office of Consumers' Counsel v. FERC*, No. 80-1316, set aside the FERC order promulgated in Opinion No. 69 and remanded the case to the FERC for any necessary additional proceedings. In Opinion No. 69, the FERC reversed an Initial Decision and granted a certificate of public convenience and necessity to Great Plains Gasification Associates ("Great Plains"), pursuant to Section 7 of the Natural Gas Act, authorizing the sale for resale of synthetic gas commingled with natural gas to support a demonstration project in the form of a coal gasification facility. As

proposed, the project would exclusively manufacture non-jurisdictional synthetic gas which would be commingled with jurisdictional natural gas prior to sale. The Great Plains partnership companies intended that their ratepayers would absorb the majority of the construction financing costs, both by guaranteeing all of the debt and the sponsors' equity investment in the project (at a 15 percent return) under most circumstances and by paying a surcharge on all interest incurred during construction on debt, taxes and on a variety of financing and other carrying charges (along with the 15 percent common equity return).

Through its grant, the FERC, in effect, extended the breadth of the RD&D regulations of Order No. 566, which provide *advance* assurance of rate treatment for RD&D expenditures by jurisdictional companies, from circumstances involving rate filings under Section 4 of the NGA, 15 U.S.C. § 717c, to include those involving certificate applications, as here, under Section 7 of the Act. Nevertheless, the District of Columbia Circuit emphatically disagreed with the FERC, holding that although Order No. 566 involves advance assurance of (Section 4) rate treatment, it does not provide for (Section 4) rate treatment in advance of (Section 7) jurisdiction.

The Court pointed out that the future jurisdictional sale of commingled gas, upon which the FERC had solely based its power to grant this customer-risk construction financing plan, may never occur and, thus, may remain forever hypothetical. Abandonment of the project conceivably could result before the completion of construction yet after Great Plains had passed through the construction surcharges in rates to its customers. As such, the Court held that the FERC exceeded its statutory authority, by regulating the construction and operation of a coal gasification plant and allowing the pass through of costs incurred thereto pursuant to the partnership's customers-risk financing package, where the Commission possesses no jurisdiction over synthetic gas development before the commingling of that gas with natural gas. Hence, the Court refused cost-of-service treatment for expenses incurred in the construction of non-jurisdictional facilities *prior to* the utilization of those facilities in "properly regulated" activities.

### 3. Unsuccessful Project Costs

On November 6, 1980, the FERC in *Columbia Gas Transmission Corporation*, Docket No. RP78-20, Opinion No. 101, addressed the proper treatment of unsuccessful project costs. In that proceeding, Columbia Gas Transmission Corporation (Columbia) sought to recover expenditures made both while participating in the Gas Artic/Northwest Project Study Group and after the filing for a FERC certification of the unsuccessful Gas Artic Project. As such, Columbia proposed to assign these Gas Artic expenditures to its cost of service and related rates, amortizing them over the next five years. The unamortized portion, it determined, would receive rate base treatment.

In affirming the Initial Decision which denied Columbia's recovery of these Gas Artic costs, the Commission expressly noted that these identical costs actually are not classifiable as RD&D expenses. Instead, it held that these expenses were "entrepreneurial" in nature and, thus, non-recoverable in jurisdictional rates. In reaching this conclusion, the FERC reasoned that the Gas Artic project had succeeded the RD&D stage, where customer reimbursement for qualified expenditures eliminates disincentives to a pipeline's incurrence of these expenses, at the



filing of the certificate application. Further, since that application ultimately was unsuccessful, Columbia did not incur these expenses in connection with requisite certificate approvals before project construction. As a result, where a judgment of benefit to its ratepayers is impossible to determine because of the denial of certification, the Commission reasoned that the risk of non-recovery of project costs should fall squarely upon the shoulders of the pipeline's stockholders and not upon those of the jurisdictional customers.

No appeals have been taken from any of the above three decisions.

## VI. TAXES

### A. Normalization

#### (1) "Full Normalization" proposed in Docket No. RM80-42.

On February 16, 1979, the D.C. Circuit Court of Appeals remanded *Public Systems, et al. vs. FERC* back to the Commission (606 F.2d 973). The basis for the remand was that Order No. 530-B did not have sufficient substantive evidence as the basis for establishing a general ratemaking policy of tax normalization.

Thereafter, on March 31, 1980, the Commission issued a Notice of Proposed Rulemaking in RM80-42 proposing a new rule (Section 2.202) under which regulated entities might elect tax normalization for ratemaking purposes for certain book-tax timing differences for which tax normalization had not been prescribed in prior Commission proceedings. Any such election would require the company to use normalization for all transactions eligible for normalization under the proposed rule. Any such election would also require that the net amount of accumulated deferred taxes be deducted from rate base, to assure that ratepayers not provide the company a return on assets financed with deferred tax funds.

In the initial and reply comments, the last of which was filed on October 10, 1980, jurisdictional companies supported the granting of an election to normalize. Although there was some conflict as to whether deferred taxes ascribable to AFUDC account balances should be handled on a gross-of-tax method or left to the election of the company, the regulated entities urged prompt issuance of the proposed rule on the grounds that normalization most accurately matches costs and revenues and results in equitable treatment of ratepayers.

A few consumer groups and state regulatory bodies, on the other hand, objected to the proposal for the reasons that flow-through presently minimizes utility rates and skepticism that tax normalized utility rates will eventually be lower than flow-through rates.

The matter is pending before the Commission.

#### (2) *South Georgia vs. Other Methods for Treating 1964-1970 Use of Flow-Through*

##### (a) *Natural Gas Pipeline Co., RP77-98 and RP78-78*

On December 24, 1980, the Commission issued Opinion No. 108 in *Natural Gas Pipeline Company*, Docket Nos. RP77-98 and RP78-78. The Commission there determined the reserved issue of the appropriate tax normalization method for the timing differences between book and tax depreciation.

Although Law Judge Kimball, in an Initial Decision issued March 3, 1980, had rejected the *South Georgia* tax normalization method in favor of Natural's

"modified" normalization method, the Commission in Opinion No. 108 adopted the *South Georgia* method for Natural. In so doing, the Commission noted that this was the first opportunity for the issue to be before the Commission in a litigated case and that, therefore, it must consider the impact not only on Natural's rates but also on other pipelines which might also seek recovery of uncompensated tax deferrals.

The Commission's specific rationale for employing the *South Georgia* method was that it would achieve a more equitable allocation of the cost of recovering uncompensated deferred tax liabilities, i.e., over ten years versus only 4.5 years under Natural's method, thus spreading the cost over a potentially wider range of customers and with a smaller annual incremental impact to the cost of service. The Commission also asserted that its decision was prompted more by an effort "to maintain uniformity in ratemaking practice" than by its acceptance of the *South Georgia* method in 17 prior settlements.

The Initial Decision had adopted Natural's "modified" method partly on the ground that *South Georgia* was not consistent with generally accepted accounting principles. The Commission reversed on this point, stating that the Addendum to APB Op. No. 2 removed regulated industries from the otherwise-controlling effect of APB Op. No. 11.

On January 22, 1981, Natural filed its Application for Rehearing of Opinion No. 108.

(b) *Panhandle Eastern Pipe Line Co.*, RP78-62

On August 18, 1980, Law Judge Gordon issued an Initial Decision requiring Panhandle Eastern Pipe Line Company (Docket No. RP78-62) to use the *South Georgia* method in amortizing the company's unfunded, deferred tax liability over the remaining life of depreciable property placed in service prior to November 1, 1978. The Initial Decision prescribed full normalization for property subsequently placed in service.

The Judge found that Panhandle's method would minimize its actual tax liability and maximize its tax allowance for rate purposes, whereas the combination of *South Georgia* and full normalization would "more accurately match the monies in Panhandle's deferred tax accounts with Panhandle's deferred tax liability." He did, however, condition the required use of the *South Georgia* method on Panhandle's receipt of an IRS ruling that use of the method would not disqualify Panhandle from taking accelerated depreciation.

*B. Gain on Reacquired Debt*

In Opinion No. 70, issued January 11, 1980, the Commission addressed the question of how to treat gain realized by a pipeline company as the result of repurchases of long-term debt before maturity at below face value. Consolidated Gas Supply Corporation had argued in Docket Nos. RP78-52 and RP79-22 that any ratemaking adjustment for gain on reacquired debt should incorporate only the gain on debt that was acquired on or after January 1, 1974, which is the effective date of related accounting and reporting regulations promulgated by Order Nos. 505 and 505-A, 51 FPC 714, 832 (1974). Consolidated argued that to do otherwise would constitute retroactive ratemaking.

The Commission rejected Consolidated's contentions in Opinion No. 70 and upheld the Initial Decision stating that the treatment of gain on reacquired debt is controlled by *Manufacturers Light and Heat Company*, 44 FPC 314 (1970), which

holds that the cost of debt should be adjusted to reflect all premiums paid and discounts realized through the retirement of debt prior to maturity. Opinion No. 70 is currently pending on review before Fourth Circuit in *Consolidated Gas Supply Corp. v. FERC*, No. 80-1219.

#### C. Consolidated Taxes

In Opinion No. 47 and 47-A, the Commission reaffirmed its determination that in calculating income taxes for cost of service purposes, pipelines should be treated on a "stand alone" basis. These Opinions are currently pending on review before the D.C. Circuit in *City of Charlottesville, Virginia v. FERC*, No. 80-1175.

### VII. RATE BASE

#### A. Acquisition Adjustments

A FERC order that Gulf Energy could not include in rate base the cost of its 1962 acquisition of the stock of Natural Gas Gathering Company was reversed and remanded in *Gulf Energy and Development Corporation v. FERC*, No. 78-2185 (D.C. Cir., February 14, 1980). The court held that there was not substantial evidence to support the Commission's finding that Gulf Energy had failed to carry its burden of establishing that the excess of acquisition cost produced consumer benefits.

#### B. Advance Payments

Following issuance of numerous opinions reversing the Commission's advance payments policy, see *Tennessee Gas Pipeline Company v. FERC*, 606 F.2d 1094 (D.C. Cir., 1979), the FERC issued an order remanding various pipeline rate proceedings involving the 30-day rule to the Administrative Law Judges' Order Remanding Advance Payments, Docket Nos. RP74-82, *et al.*, issued June 36, 1980. Most of these remanded proceedings have been resolved through settlements.

#### C. Cash-Working Capital

While the Commission issued no formal decisions regarding cash-working capital issues affecting natural gas pipelines, some interest appears to exist in various pending rate proceedings for the use of lead-lag studies.

#### D. Depreciation

An important depreciation issue was litigated, but not yet decided, in *Algonquin Gas Transmission Company*, Docket No. RP80-72. The staff witness presented a depreciation study reflecting committed as well as "supplemental" future supplies. The company presented testimony challenging use of data relating to unknown and uncommitted gas supplies. Cross-examination on this issue were completed in late November, 1980.

The Commission reviewed the issue of net negative salvage value (where the retirement cost of a facility exceeds its salvage value) in reviewing an Initial Decision which set depreciation rates for Columbia Gulf's offshore plant. *Order Affirming in Part and remanding in Part Initial Decision*, Docket Nos. RP75-105 and RP76-94, issued December 12, 1980. The Commission remanded for further evidence the issue of the proper factor for negative salvage. Special emphasis was placed on the lack of sufficient data on the removal process. Accordingly, the Commission stated that it would like further information on (1) whether pipeline

and producers would share removal costs and (2) the specific functions and practices of diving and barge service contractors. In reaching its decision to remand, the Commission rejected the alternative of instituting a generic rulemaking proceeding.

#### VIII. RETURN

The major development in the area of rate of return issues was not the range of returns granted in Initial Decision and Commission orders; instead, the key Commission action in this area was the endorsement of a return on total capital approach in *Mid-Louisiana Gas Company*, Docket No. RP73-43, Initial Decision issued February 29, 1980. The parties had used the typical weighted cost of capital approach, with substantial capitalization ratios to be used for the Grand Bay facility (the jurisdictional subsidiary of the parent, Gulf Oil Corporation). The presiding Judge rejected the hypothetical capital structure approaches due to the absence of (1) comparable firms which are independently financed and (2) any similarity of risks as between Grand Bay and its parent. Because this was a Section 7 proceeding, the Judge found that he had the flexibility to abandon the effort to develop a hypothetical capital structure. Consequently, he held that "the allowed return for Grand Bay should be the product of a specified overall rate of return applied to the total capital structure invested in Grand Bay."

#### IX. TEST PERIOD

Positions taken by the Commission Staff on the use of the post-test period data in two rate cases during 1980 suggested that the Staff's policy on use of such data turns on the perceived role of the filing pipeline in administrative delay of the case. In *Transwestern Pipeline Company*, Docket No. RP78-88, in answering an appeal by Transwestern from the Presiding Judge's decision to permit Staff discovery of certain out-of-test-period cost of service data, the Staff argued that in gas proceedings the Commission attempts to base rates as closely as possible on actual experience, and accordingly is properly often willing to rely on post-test period data, especially where there had been lengthy delays before hearing.

However, in *Distrigas of Massachusetts Company*, Docket No. RP79-23, the Commission Staff opposed the applicant's proposed use of costs occasioned by post-test period events. The Staff contended that to admit post-test period data at hearing would reward the company for administrative delays of its own making. The Staff argued that these delays occurred largely because Distrigas had insisted on presenting a contested settlement to the Commission, certain features of which the Commission found unjust and unreasonable, and because Distrigas had requested a hearing rather than accept the modifications recommended by the Commission which would have eliminated the objectionable features of the settlement.

#### X. TRACKING PROVISIONS

##### A. Prepayment Trackers

During 1980, some pipelines proposed to modify the purchased gas adjustment (PGA) provisions of their tariffs to provide authority to flow through any carrying charges associated with prepayments pursuant to take-or-pay provisions

of their gas purchase contracts. The Commission's response has been to reject those modified sheets as contrary to the PGA regulations, Section 154.38(d)(3). However, these proposed trackers were allowed by the Commission to be considered as an issue in the Section 4 proceedings, *see Natural Gas Pipeline Company of America*, Order Accepting Certain Tariff Sheets, Docket No. RP80-107, issued June 30, 1980.

## B. Purchased Gas Adjustment Clauses

### 1. Conduit Tracking

In an acknowledged departure from its policy against permanent rate adjustment provisions for most cost items, the Commission authorized Algonquin Gas Transmission Company and Texas Eastern Transmission Corporation to include provisions in their respective tariffs tracking the cost of storage service rendered by Consolidated Gas Supply Corporation for the benefit of Algonquin's and Texas Eastern's customers. "[I]n this case and similar cases where the 'middleman' pipeline acts only as an accounting conduit, waiver of Sections 154.38(d)(3) and 154.63 of the Regulations is appropriate." *Texas Eastern Transmission Corporation, et al.*, Docket No. CP80-170, *et al.*, Order issued June 16, 1980, p. 5.

### 2. Emergency Purchases

The sixty-day emergency purchase program of Section 157.22 has produced a sizable volume of litigation over the years as Staff or the customers challenge the prudence of short-term purchases from intrastate suppliers at prices in excess of the area or national rates. Only in a few instances have emergency purchases been deemed imprudent by the Administrative Law Judges. Two cases in that category were reviewed this year by the Commission; in both cases, the finding of imprudence was reversed.

In *Panhandle Eastern Pipe Line Company*, Docket No. RP73-36 (PGA78-3), the Administrative Law Judge held that the company had acted imprudently in failing to take early steps to meet the projected supply shortage and in paying an excessive price, Initial Decision, issued June 21, 1979. By order issued March 5, 1980, the Commission reversed and remanded the Initial Decision, seeking further evidence on the issues of need and price. A settlement in this docket was approved by the Commission on July 17, 1980.

In *Natural Gas Pipeline Company of America*, Docket No. RP71-125 (PGA78-2), the Administrative Law Judge also found the purchasing pipeline to have acted imprudently. In Opinion No. 107, issued December 22, 1980, the Commission reversed, holding that the ALJ had not properly applied the prudence test. Because Natural's curtailment plan is framed in terms of customer entitlements, rather than end-use profiles, the ALJ adopted a test which focused on Natural's ability to supply its entitlements. The Commission disagreed, holding that a broader focus was in order—whether management thought the purchases were necessary to allow entitlements to be met, regardless of whether the customer was high or low priority. This result, inferentially, links prudence to a volumetric rather than an end-use analysis.

### 3. Periodic Review Requirements

In *Florida Gas Transmission Corporation*, Docket No. RP79-64, the parties submitted briefs on the issue of whether the refund obligation under the 36-month filing requirement, 18 C.F.R. § 154.38(d)(4)(vi), applies solely to sales rates. Staff and the intervenors argued that the refund obligation extends to transportation rates since the purpose of the 36-month review is to remove any imbalance between total system jurisdictional costs and revenues. Florida Gas disagreed, claiming that since only sales rates are affected by the PGA filing, only sales rates are subject to a refund obligation. The Commission considered a proposed order in late November, but voted, instead, to set the matter for oral argument.

### 4. Pipeline Production

1980 saw the continuing evolution of the Commission's pipeline production rules under the NGPA, as the Commission revised and refined the concept of "first sales." Order Nos. 58, 98, and 102 in Docket Nos. RM80-7 and RM80-8 basically provide that pipeline production from an affiliate is entitled to first sale treatment. If the production is owned by the pipeline, it is entitled to the NGPA rate unless the gas was previously priced on a cost-of-service basis. These orders are presently on appeal in the Fifth Circuit and D.C. Circuit.

One aspect of the pipeline production issue has been presented in a number of PGA dockets. Section 601(b)(1)(E) of the NGPA provides that any first sale between the pipeline and its affiliate will be deemed unjust and unreasonable if the amount exceeds "the amount paid in comparable first sales between persons not affiliated with such interstate pipeline." This "affiliated entities" test has been mentioned in a number of PGA dockets, and is the key criteria for the Commission decision to authorize pass through of the costs of pipeline production.

### 5. Storage Gas

The commission recently confirmed that the pricing formula used by Consolidated Gas Supply Corporation in its PGA for gas withdrawn from system storage and sold to its customers is proper. For accounting purposes, Consolidated uses a LIFO (Last In First Out) pricing formula based on a calendar year. During the January through March withdrawal season, storage withdrawals are valued at the projected average gas cost for the current calendar year even though the actual molecules withdrawn were injected during a prior year. The "Replacement Reserve" (Account 265) is used to reconcile differences between current and past year's costs. The same method of accounting is used for gas withdrawn from storage by North Penn Gas Company and was similarly approved for ratemaking purposes on the same day. *Consolidated Gas Supply Corporation*, Docket Nos. RP79-22 and RP78-52, "Order Affirming Initial Decision," January 16, 1981; *North Penn Gas Company*, Docket No. RP79-68, "Order Affirming Initial Decision," January 16, 1981.

## 6. Take-or-Pay

While the Commission has yet to issue a formal order on the subject, PGA filings have provided the impetus for Commission discussion and Staff data requests relating to the question of whether any take-or-pay volumes were included in the filing.

### C. Other Trackers

Several other notable determinations have been reached. First, the Circuit Court of Appeals for the District of Columbia affirmed the Commission's orders requiring that East Tennessee Natural Gas Company and Tennessee Natural Gas Lines pass through their PGA clauses not only commodity rate surcharges associated with curtailments as imposed by their supplier, Tennessee Gas Pipeline Company, but also demand charge credits associated with such curtailments. *East Tennessee Natural Gas Co., et al. v. FERC*, 631 F.2d 794 (D.C. Cir. 1980).

Second, the Commission has adhered to its position that pipelines must refund the full amount of collections from customers recovering the Louisiana First Use Tax in the event the tax is declared unconstitutional, regardless of the amount refunded by Louisiana. (Order 10-C issued April 24, 1980 in Docket No. RM78-23). Suits considering the constitutionality of the tax are pending before the U.S. Supreme Court in a complaint initiated by eight States (*State of Maryland, et al. v. State of Louisiana*, October Term 1978, No. 83 Original; currently in proceedings under Special Master John F. Davis) and before the Fifth Circuit (*FERC v. Shirley McNamara, et al.*, No. 79-1403). A suit is also pending before the Fifth Circuit to review FERC Order No.s 10, 10-A, 10-B and 10-C (*Tennessee Gas Pipeline Co. v. FERC*, No. 78-3816).

Third, since the December 20, 1979 Panhandle decision (*Panhandle Eastern Pipe Line Co. v. FERC*, 613 F.2d 1120 (D.C. Cir. 1979)) which rejected the Commission's condition requiring crediting of revenues from transportation service to customers not receiving such service, settlements respecting similar service have included tracking provisions reflecting both transportation costs and revenues.

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