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NEW RISKS FOR LDCS AND MEANING OF "RELIABILITY" DISCUSSED AT AGA ANNUAL MEETING

LDCs must make a strong case for themselves before state regulators if their equity returns do not reflect the increased risks of doing business under Order No. 636, according to Dennis Nagel, Chairman of the Iowa Utilities Board and the National Association of Regulatory Utility Commissioners (NARUC). Nagel was one of three panelists discussing Order No. 636 impacts on LDCs at the annual meeting of the American Gas Association in Washington, D.C. on 10/11/93. The other two panelists were FERC Commissioner William L. Massey and Donald Dufresne, vice president, Salomon Brothers.

Commissioner Massey started off with an overview of the restructuring rule, acknowledging that he finds straight fixed variable (SFV) rate design "troubling." He also expressed concern about consumer protection in the event of curtailments. Massey said he supported Order No. 636 in the interest of regulatory certainty for the industry and because FERC provided for mitigation of cost impacts, which will be reexamined in each new rate case. The Commission is "pragmatic," Massey said, and "committed to fine-tuning" Order No. 636 as the industry gains experience with pipeline restructuring in the coming months.

With pipelines out of the merchant business, new elements of risk for LDCs are commodity prices and supply forecasting, according to Iowa Board Chairman Nagel. Pipelines will no longer be in a position to absorb variations when some LDCs overestimate or underestimate their peak season requirements. Nagel suggested some strategies for LDC responses to Order No. 636-related risk, including use of secondary markets in capacity release and gas futures, reliance on gas storage, and accurate load forecasting and control. For risks unrelated to Order No. 636, such as environmental cleanup, he emphasized the need for integrated resource planning and demand-side management.

Dufresne argued that current LDC returns approved by state regulators do not match the increased risks, which have "skyrocketed." Under Order No. 636, pipeline risk has decreased, he noted, as a result of virtually certain recovery of fixed costs -- perhaps warranting lower pipeline returns. According to Dufresne, three recent "disastrous" rate decisions by state regulators in Arizona, Washington state and Washington, D.C., are "frightening."

Facing LDCs are their relative unfamiliarity with merchant functions previously performed by pipelines, a likely increase in their fixed payments as a result of SFV rate design, an estimated passthrough of $3 to $5 billion in transition costs, possible return of take-or-pay problems due to growing reliance on long-term contracts, escalating wellhead prices, and newly unbundled gas storage costs. If state regulatory trends continue, Dufresne suggested that utilities may face dividend reductions, loss of access to capital markets, layoffs, deterioration in the quality of service, and slowing of demand for natural gas.

On the crucial question of whether the benefits of Order No. 636 will, in fact, outweigh the costs, Massey counselled that "the jury is still out," while Nagel described himself as "skeptical." Dufresne's position suggested extreme pessimism.

Recent initiatives of the Natural Gas Council's Reliability Task Force were the subject of another panel on the same day. The nine-member Task Force, chaired by David W. Biegler, President and CEO of Enserch Corp., includes representatives from pipelines, LDCs, producers, marketers and the Canadian gas industry. There are four subcommittees, which focus on the role of regulation in supporting long-term reliability, contingency planning, communications and data availability (including EBBs and a Gas Industry Standards Board). The purpose is to develop "broad principles and guidelines" for cooperation in the interest of improving the public's perception of the industry -- and, specifically, its "reliability." The industry has probably hurt itself by use of such terms as "interruptible" and "curtailment," Biegler suggested. According to the Task Force definition, gas qualifies as a "reliable" fuel if over time -- repeatedly -- customers receive what they expect, when

they expect it, where they expect it, at the agreed-upon price. What they can expect, warned Richard E. Terry, Chairman and CEO of Peoples Energy Corp., depends on what they contracted for. For example, if an end-use interruptible customer assumes he will be taken care of one way or the other, Terry said, he may be in for a big surprise. "Interruptible" means that someone will have to be interrupted. If, in fact, the customer cannot be interrupted and lacks dual fuel capability, he had better contract for firm, or get backed up by an LDC. Conversely, those supplying firm customers must have sufficient reserves already under contract to meet their obligations. Lastly, Terry continued, LDC planners should diversify their supply in terms of both geographic area and supplier -- without trying to rely strictly on low cost contracts.

As another method of promoting confidence in gas, Biegler noted that the AGA Board on 10/10/93 approved the Task Force's proposal for weekly compilation of working gas storage data to assure customers of the adequacy of gas supplies. The data will be acquired from storage operators, aggregated, and made available on a regional basis only. AGA will maintain the anonymity of storage companies. The timing is not yet definite. An AGA spokesperson would indicate only that the data will be ready "before or during the winter heating season." Dissemination will be electronic.

Lastly, in the area of data availability, the Task Force announced a meeting on the formation of a Gas Industry Standards Board to take place on October 20 in the EIA Auditorium of the Department of Energy, 1000 Independence Avenue, S.W., Washington, D.C.

AGA SURVEY PREDICTS AVAILABLE SUPPLIES WILL MEET OR EXCEED MAXIMUM PEAK MONTH DEMAND THIS WINTER

At a press briefing on 10/12/93, American Gas Association President Michael Baly announced the release of a report on gas supply availability in the 1993-94 winter heating season based on a survey of distributors, pipelines, and producers. The report includes an analysis of supply and demand balance in the coldest weather; several cases describing gas acquisition practices; gas supply options, techniques, and terminology for LDCs; and review of pipeline services.

Nineteen major pipelines and 60 LDCs responded to AGA's survey. The pipeline sample accounted for about 66% of transportation throughput during January 1993.

AGA assumed an "aggressive" maximum peak-month demand of 2,583 Bcf for January 1994, even though the highest peak-month demand on record is 2,426 Bcf in January 1979. Available supplies are expected to match or exceed demand in the peak month. Conventional gas production will likely account for 1,590 Bcf or about 60% of total peak-month supplies, storage withdrawals about 820 Bcf or more than 30%, Canadian and LNG imports about 205 Bcf or 8%, and supplemental sources as much as 13 Bcf or 0.5%. By October 1993, more than 3 Tcf of working gas will be in storage.

In a separate assessment of pricing trends, Baly said that residential prices this winter "will vary widely" by region, state, and company, but the average will be "somewhat above last year's levels" due to a variety of factors. Wellhead prices are now higher, and straight fixed variable (SFV) rate design will increase the transportation cost component of residential service. State regulatory treatment of cost shifts is another variable.

There will be some winners and some losers, Baly stated. For the losers, the level of increase "will vary substantially" depending upon each LDC's mix of services, the LDC's load factor, the load factor of the pipeline serving the LDC, and the need for and availability of storage. In addition, some increases may be attributable to other factors such as pipeline expansion costs, which may be rolled in or treated incrementally. He noted that Order No. 636 requires mitigation of any SFV-related cost shifts exceeding 10%.

Given current price trends and expected variances, AGA decided that estimating a national average residential increase or decrease "would be essentially meaningless and possibly misleading to our customers." Whether the cost of home heating this winter goes up or down depends primarily on the weather, Baly insisted, and not gas prices -- which for many will be lower this winter than 10 years ago.

TEXAS EASTERN PROPOSES EXPANSION OF MAINLINE CAPACITY TO PROVIDE INCREMENTAL FIRM TRANSPORTATION FOR CNG

On 10/1/93 Texas Eastern Transmission Corp. applied for authority to construct approximately 26 miles of 36-inch looping and replacement pipeline along with additional compression, at an estimated cost of $39.2 million, in order to provide 100,000 dth/d of incremental firm transportation requested by CNG Transmission Corp. The facilities proposed by Texas Eastern would constitute an "operational loop" on CNG's system and enable CNG to render 100,000 dth of firm transportation and/or storage service to customers served off its PL-1 Line, including Virginia Natural Gas Co., Washington Gas Light Co. and Public Service Co. of North Carolina.

Texas Eastern's proposed project was submitted as part of the Panhandle Eastern Corp. Flex-XTM program announced last March. Flex-XTM involves a 10-year expansion program to add 700,000 Mcf/d of firm transportation capacity on Panhandle Eastern's four interstate pipelines: Texas Eastern, Panhandle Eastern Pipe Line Co., Trunkline Gas Co. and Algonquin Gas Transmission Co. The program is designed to alleviate long-range planing uncertainties by providing the expanded capacity only when needed and in increments to accommodate customers' present and future requirements. In accordance with this concept, a first annual open season was held during the period 7/1/93-8/13/93 to accept Flex-XTM nominations. Texas Eastern's instant application results from this open season.[1] (See REPORT NO. 1919, p26.)

Specifically, Texas Eastern proposes to increase mainline transmission capacity between its Crayne Farm meter station in Waynesburg County, Pennsylvania, and its Chambersburg Compressor Station in Chambersburg County, Pennsylvania. CNG interconnects with Texas Eastern at both these points. It therefore uses this segment of Texas Eastern's system as an operational loop. The incremental facilities will enable CNG to deliver 100,000 dth/d into Texas Eastern's system at Crayne Farm for firm transportation to Chambersburg, where the gas will be delivered in CNG's PL-1 Line.

CNG will file a related application for certificate authority to construct facilities necessary to render downstream service for customers on its PL-1 Line.

Texas Eastern proposes to charge CNG an incremental reservation rate of $7.581/dth as an initial rate under NGA Section 7. This rate would be separately stated as part of Texas Eastern's Rate Schedule FT-1 rate schedule for Part 284 open access transportation. The company said incremental rate treatment is justified because the proposed compressor unit and replacement pipeline facilities will be constructed at CNG's request and will specifically benefit CNG and its customers. Also, the requested initial reservation rate is consistent with recent Commission decisions regarding other construction applications. For example, in July 1993, the Commission authorized Texas Eastern to charge an NGA Section 7 initial rate not subject to refund as a separately stated, incremental rate for its Integrated Transportation Project (Phase I), even though the transportation service will be rendered under Texas Eastern's Part 284 open access Rate Schedule FT-1.

In addition, Texas Eastern stressed the need for initial rate certainty which, it said, is particularly important for the Flex-XTM program offering regular annual expansion opportunities to assist shippers in planning for incremental market requirements. "If rate certainty is not assured, shippers'

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[1] Earlier, on 7/19/93, Texas Eastern (CP93-565) requested authority to construct pipeline looping costing an estimated $18.1 million to provide 18,171 dth/d of firm transportation for four northeastern utilities (Philadelphia Electric Co., UGI Corp., Brooklyn Union Gas Co. and Elizabethtown Gas Co.). The services would be provided between CNG Transmission Corp.'s Oakford Storage Field in Westmoreland County, Pennsylvania and various existing delivery points. This was Texas Eastern's first application under the Flex-XTM program. (See REPORT NO. 1937, pp35-36.)

planning abilities would be greatly diminished and a principal benefit of the Flex-X Program would be negated."

Texas Eastern urged approval of its application without an at-risk condition since it has a precedent binding agreement with CNG covering 100% of the capacity of the proposed facilities.

TEXAS EASTERN AND ALGONQUIN PROPOSE EXPANSION OF FACILITIES TO PROVIDE INCREMENTAL FIRM SERVICE OF 65,997 DTH PER DAY TO NORTHEAST SHIPPERS AS PHASE II OF "INTEGRATED TRANSPORTATION PROJECT"

On 10/1/93 Texas Eastern Transmission Corp. (CP94-5) and Algonquin Gas Transmission Co. (CP94-1) requested certificate authority to construct and operate facilities necessary to provide firm incremental transportation service to certain shippers. The proposals represent Phase II of the so-called "Integrated Transportation Project" (ITP) which Texas Eastern and Algonquin originally devised as a "packaged" transportation service from Gulf Coast, Arkoma Basin and Midcontinent producing areas to Northeast consuming markets using facilities of Trunkline Gas Co. and Panhandle Eastern Pipe Line Co. as well as Texas Eastern an Algonquin.[1] The Phase II applications propose additional construction costing over $120 million to provide firm service totalling 65,997 dth/d.

Background

Applications for the ITP were initially filed in November 1991. At that time, Texas Eastern proposed to construct 126 miles of pipeline and add 59,150 horsepower of compression, at an estimated cost of $280.2 million, in order to provide 261,500 dth/d of incremental firm transportation to six shippers (including Algonquin)[2] on a phased-in basis over a three-year period ending 11/1/95. Algonquin proposed construction of pipeline loop and compressor facilities, at an estimated cost of $56 million, in order to provide 60,500 dth/d of incremental firm transportation (45,500 dth/d for Boston Edison Co. and 15,000 dth/d for Yankee Gas Services Co.) beginning 11/1/94 and an additional 15,000 dth/d for Yankee beginning 11/1/95.

In March 1992, Texas Eastern and Algonquin amended their applications to divide the ITP into two phases, the first involving services to commence in November 1993 or November 1994 and the second involving services scheduled to commence November 1995. The amendments were largely prompted by unanticipated regulatory delays encountered by Boston Edison with respect to its proposed Edgar Energy Park electric generating facility. Transportation slated for this facility was deferred to Phase II. Subsequently, on 7/2/92, Texas Eastern and Algonquin withdrew Phase II of their respective ITP applications due to an indefinite delay in the Edgar project. This left the Phase I applications which, as amended, involved construction of facilities costing an estimated $209.7 million by Texas Eastern to provide 201,000 dth/d of incremental firm transportation for five shippers, and construction of $12.5 million of facilities by Algonquin to provide firm transportation of 15,000 dth/d for Yankee.

FERC generally approved nonenvironmental aspects of the Phase I applications on 1/14/93. However, it directed that the ITP services be performed under Texas Eastern's and Algonquin's Part

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[1] Under the ITP proposals, Texas Eastern and Algonquin will also provide "agency services" -- namely, coordinated scheduling, nominating, balancing and billing on affiliated upstream pipelines -- for any shipper requesting such services. This is intended to provide the administrative convenience of "one-stop" transportation service. However, the agency feature is optional and not a condition for obtaining ITP service.

[2] The other five shippers are: UGI Corp., Public Service Electric & Gas Corp., Delmarva Power & Light Co., Philadelphia Gas Works and Yankee Gas Services Co.

284 open access blanket certificates instead of case-specific certificates. The Commission also rejected 100% incremental demand charges proposed by the two pipelines, and instead ordered development of ITP surcharges which, when added to existing Part 284 rates, would cover their incremental costs of service.

Some six months later, on 7/16/93, the Commission issued final certificates to construct and operate the ITP facilities. In addition, FERC granted rehearing of the ITP surcharge approach and permitted Texas Eastern and Algonquin to establish separately-stated, incremental rates under Part 284 for the ITP service. As requested, these rates were authorized as initial rates not subject to refund. The Commission was persuaded by the two pipelines that such rates are necessary to provide regulatory certainty. (See REPORT NOS. 1911, pp9-12; 1938, pp11-13.)

Phase II Applications

Texas Eastern (CP94-5) proposes to construct over 49 miles of 36-inch pipeline loop and replacement facilities, at an estimated cost of $81.4 million, in order to provide firm transportation service of 65,997 dth/d for three shippers beginning 11/1/95. The bulk of the incremental volumes will go to Algonquin (45,997 dth/d); UGI and Delmarva also will receive 10,000 dth/d each.

Algonquin (CP94-1), in turn, proposes to construct or uprate about 25 miles of pipeline and rebuild a meter station, at an estimated cost of about $40 million, in order to provide firm transportation service of 45,500 dth/d on behalf of Boston Edison Co. Boston Edison will use the gas at its New Boston electric generating station which, pursuant to a consent order with the Massachusetts Department of Environmental Protection, must be converted 100% to gas firing by April 1995.

Transportation upstream of Texas Eastern will be provided by Trunkline and Panhandle, among other pipelines, under their open access transportation rate schedules.

Consistent with the Phase I certificates issued 7/16/93, Texas Eastern and Algonquin both seek to establish separately stated, incremental rates as initial rates not subject to refund. (Texas Eastern and Algonquin proposed 100% demand rates of $19.901 and $19.159, respectively.) Texas Eastern contended that the certainty of an initial rate is a critical element for pipeline companies in deciding whether to go forward with construction. "Given the large sums of money involved in pipeline construction projects, some initial assurance of a return both of and on fixed costs is vitally important."

In addition, Texas Eastern noted that executed precedent agreements with its ITP shippers are binding agreements covering 100% of the capacity of the proposed facilities for 20 years. Hence, Texas Eastern urged that no at-risk conditions be attached to approval of its project.

FERC APPROVES GREAT LAKES' ORDER NO. 636 COMPLIANCE FILING FOR IMPLEMENTATION ON NOVEMBER 1

On 10/1/93 the FERC mostly denied rehearing of an order dated 7/2/93 accepting Great Lakes Gas Transmission Limited Partnership's Order No. 636 compliance filing (RS92-63) subject to numerous modifications, and approved Great Lakes' revised filing submitted in August to be effective 11/1/93.

As in numerous other pipeline restructuring orders, FERC granted waiver of Part 284 reporting requirements to allow addition and deletion of receipt/delivery points and temporary capacity releases without the need to file otherwise prescribed reports.

Rate Issues

The Commission stuck to its prior rejection of Great Lakes' rolled-in rate proposal and its acceptance instead of Great Lakes' alternative incremental rate proposal, with modifications. Great Lakes and its three expansion shippers affected by FERC's incremental rates decreed in Opinion Nos. 367 and 368 -- TransCanada PipeLines, Northern Minnesota Utilities (NMU) and Midland Cogeneration Venture -- all reargued on rehearing, among other things, that rolled-in rates are necessary to realize the Order No. 636 goal of transportation equality. FERC responded that Order No. 636 requires equal access to transportation services regardless of the source of the gas, but this does not imply that rates must be equal. Order No. 636 does not preclude cost-based differences in rates, the Commission declared. "The existence of a rate differential between pre-expansion and incremental expansion rates does not impact access to supply sources. The quality of transportation service available to both the pre-expansion and incremental expansion shippers will be the same regardless of the identity of the supplier. That is all that Order No. 636 requires."

Further, FERC was unpersuaded by TransCanada's claim that rolled-in rate treatment for the expansion projects involved in Opinion Nos. 367 and 368 would have only a 19% impact on systemwide rates -- less than the 24% impact which the Commission found acceptable in approving a major Northwest Pipeline Corp. expansion in June 1992. The Commission said TransCanada's analysis was flawed on two counts. First, FERC accepted rolled-in rate treatment for Northwest's expansion based on the pipeline's assurance that the impact would be 5¢/dth. Second, TransCanada's figures are wrong. Roll-in of Great Lakes' expansion facilities would increase pre-expansion shippers' rates by 67%, or 14.5¢/dth. FERC also distinguished its approval of rolled-in rates for Transcontinental Gas Pipe Line Corp.'s Mobile Bay facilities, which caused a rate impact of only 0.45¢/dth or 3% on existing customers.

The Commission asserted that the issue of rolled-in versus incremental design of Great Lakes' transportation rates is a factual issue that has already been explored in Great Lakes' pending rate proceeding (RP91-143) and need not be reheard in the restructuring context. While certain portions of Great Lakes' rate case were consolidated with its restructuring docket, FERC said it has since identified issues in restructuring proceedings that should be resolved in pending rate cases. However, the Commission added, it may establish a generic proceeding in the future to consider rolled-in versus incremental rate treatment questions.

In regard to some related issues, FERC reaffirmed its prior rulings that (1) rates for released capacity must be restricted to the applicable maximum tariff rate for the service being released, not capped at the maximum incremental rate available on the Great Lakes system; (2) pre-expansion shippers exercising first refusal rights to renew capacity should not be assessed incremental rates because they did not cause Great Lakes to incur the incremental expansion costs; and (3) new customers using pre-expansion capacity should not be required to pay the incremental rate for their service. The Commission reasoned that use of an incremental rate cap for all released capacity would increase the potential amount of profits to be realized by Great Lakes, releasing shippers or expansion shippers, and that it is best not to alter the financial position of the parties at this time. According

to the Commission, "it is prudent to wait" until "both the parties and the Commission . . . gain experience with the operation of capacity release markets."

With respect to assigned, relinquished or renewed capacity, the Commission agreed with TransCanada, NMU and others that the situation of new and renewing shippers is somewhat different from that of pre-expansion customers under existing contracts. However, since most of Great Lakes' existing transportation contracts do not expire until after the year 2000, "there is no immediate need to determine the rate for new and renewed capacity." Accordingly, it is "premature at this time to set a rate applicable for new and renewed contracts other than the currently applicable rate." Further, the Commission added, implementation of a policy requiring that new and renewing shippers served by pre-expansion capacity pay incremental rates could be "exceedingly complex." Therefore, all parties should have an opportunity to fully explore the issues presented by this proposal. In Great Lakes' next rate case, "parties are free to advocate a change in rate treatment for new, renewed and existing contracts, should they desire to do so."

Finally, the Commission denied rehearing of requirements that Great Lakes make a reasonable projection of interruptible/overrun (I/O) volumes for purposes of cost allocation, and that it share 90% of I/O revenues with firm shippers absent any deduction for a so-called "cost and efficiency allowance" (equal to the pipeline's operating and maintenance expenses adjusted annually for inflation). While a previously approved rate case settlement incorporated a 90/10 revenue sharing mechanism including the "cost and efficiency" allowance, the Commission noted that its approval there was subject to reconsideration in the restructuring case. Upon reconsideration, FERC found that the cost and efficiency allowance "would act simply to increase revenue retention to Great Lakes with no offsetting benefit to the ratepayer."

Conversions to Part 284 Open Access Service

The Commission adhered to its prior rulings that Section 7(c) shippers may not elect to convert only part of their existing service to open access transportation, and may not have a continuing right of conversion. TransCanada and NMU argued that Section 7(c) customers should be permitted to convert any portion of their existing individually certificated service now or in the future. In addition, TransCanada contended, denying partial conversion is inconsistent with the Commission's stated purpose of restructuring, namely, to afford transportation customers maximum flexibility in designing their services.

FERC conceded that Order No. 636-B declined to mandate the mechanics of conversions and left such matters to individual cases. However, the Commission noted, in implementing Order No. 636, it has not required pipelines to allow partial or continual conversions. In this proceeding, FERC observed, there may be adverse cost allocation and rate implications for Great Lakes if conversions were allowed on a continuing basis. Therefore, since Great Lakes did not propose partial or continual conversions, it should not be forced to provide this flexibility outside of a full Section 4 proceeding.

Right-of-First-Refusal Procedure

The Commission directed some additional revisions to Great Lakes' right-of-first-refusal mechanism, including elimination of language that competitive bidding will not apply if Great Lakes finds a renewing shipper's notice to be acceptable and consequently enters into a new transportation agreement with that shipper. FERC agreed with certain parties that this language creates the potential for abuse of market power and that all renewal arrangements should be subject to EBB posting and competitive bidding. "The competitive bidding process will prevent any possibility of discriminatory conduct by Great Lakes by letting the marketplace decide the value of all terminating contracts." Further, the use of objective standards removes "the stigma of operating behind closed doors and in an anticompetitive manner."

In addition, Great Lakes must allow partial renewals of existing service; must establish a 30-day response period for shippers to match competing offers for expiring capacity; and must delete the requirement that an existing shipper notify Great Lakes of the price it is willing to pay for continued service in advance of the bidding process. As it previously noted in the July 2 order, the Commission said nothing in Order No. 636 requires an existing shipper to set the offering price.

EBB WORKING GROUP 5 SELECTS PETROLEUM INFORMATION CORP.'S GRID AS COMMON TRANSACTION POINT CODE, BUT RETAINS COMPROMISE MAKING USE OF CODE OPTIONAL

On 10/12/93 EBB Working Group 5 (WG5) submitted final recommendations concerning common codes transaction points, which are one set of standards governing electronic bulletin boards (EBBs). In a rulemaking notice (RM93-4) issued 7/29/93, FERC invited comment on consensus standards recommended by other industry working groups as of 7/1/93. At that time, WG5 had not yet reached consensus on either an assignor of common transaction point codes or a code structure. Therefore, FERC gave WG5 participants an extension until 10/1/93, after which time it proposed to decide these matters itself. WG5 had completed its deliberations by then, but not its report.

WG5 finally selected Houston-based Petroleum Information Corp. (PI) for the assignment, verification, and ongoing maintenance of common transaction point codes and PI's "GRID" as the code structure. Under WG5's final consensus, parties who would benefit from using common codes -- for example, shippers on multiple pipelines -- may use them. A complete and verified database of such codes will be available. However, those shipping on only one or two pipelines may continue to use proprietary codes unless and until their requirements change, thereby avoiding implementation costs that might outweigh benefits. Demand for use of common codes will be customer-driven, WG5 emphasized, although jurisdictional interstate pipelines may voluntarily offer to accept them.

In a 10/13/93 notice, FERC invited comments by 10/21/93 on WG5's recommendations. The October 12 filing does not address common codes for gas companies. FERC previously gave WG5 participants until 2/1/94 to reach consensus on this issue.

Background

EBBs are required under Order No. 636 to provide shippers with equal and timely access to information on capacity available through release transactions or directly from pipelines. Common transaction point codes are "extremely important" for more efficient capacity markets, according to FERC. In its July 1 report, WG5 adopted an initial compromise between those favoring existing proprietary codes and those favoring new common codes. Under that compromise, a third party (a Code Assignor) would maintain a system for cross-referencing the two, with each customer performing a translation. FERC questioned whether this proposal is workable and suggested that perhaps pipelines themselves should perform the translation. (See REPORTS NOS. 1935, pp20-21; 1937, pp24-28; 1939, 1-4; 1944, 11-15.)

Final Recommendations on Transaction Point Codes

WG5's recommendations build upon the compromise described above. The types of transactions to be facilitated by common codes include -- but are not limited to -- capacity release, capacity availability, scheduling, title transfer, and custody transfer. A unique common code will allow users to identify multiple proprietary codes associated with a single location, such as an interconnect. All 16-digit proprietary codes will share the same first 10 digits.

Under WG5's recommendations, owner/operators will provide sufficient information about gas transaction points to the Code Assignor, who will establish, free of charge, a cross-reference between the proprietary codes and the common codes assigned to those points. Owner/operators will verify that the information is correct. They will also ensure that all information is kept current, and quickly

forward additions, deletions and changes to the Code Assignor. Owner/operators can continue to conduct business using their proprietary codes for all gas transactions. Business trading partners who operate across multiple pipelines can use the common codes to coordinate their transactions, while using the cross-reference system to translate such codes into proprietary codes when they are submitting gas transaction data to the pipelines. Customer demand will drive further efforts to implement the use of common codes throughout the industry.

PI will coordinate with Data Providers to establish an implementation schedule. According to WG5, initial discussions with PI indicate that it will take approximately six months to establish and validate common codes for "a large majority" of transaction points on jurisdictional interstate pipelines. Thus, if the process begins this winter, the database may be finished by the 1994-95 winter heating season.

Following this process, the development of common codes for transaction points on nonjurisdictional intrastate pipelines will be strictly voluntary. The intent is eventual creation of a common code for every transaction point on the national grid. WG5 recommended that, within 30 days of its order in this proceeding, FERC require all jurisdictional interstate pipelines to name a liaison to PI.

PI has agreed to be both a Code Assignor and a Distributor. It will be required to provide a one-time copy of the entire common code database upon request, at no cost to users except postage and handling costs, but not periodic updates or selective records. PI must correct errors brought to its attention, but it "will not be required to warrant that information is 'correct' as measured against an objective or other standard."[1] All information will be in the public domain. WG5 noted that, over the last five years, PI has already assigned about 100,000 GRID codes to natural gas transaction points.

There will be three types of contractual arrangements involving common codes: between PI and a group representing "a large segment" of the natural gas industry, between PI and other authorized Code Distributors, and between a Code Distributor and a Code User. The gas industry will retain rights and ownership of the common code and the cross-reference system through a consortium of major gas trade associations or, ultimately, a Gas Industry Standards Board. Code Distributors may not charge for the common codes, but they may charge for any "value-added" services. Code Users may contract with Code Distributors for only those codes required for their transactions. Contracts would specify the frequency with which the user's database is updated.

In closing, WG5 posed the question of how changes in demand might affect future implementation of common codes. It promised in its 2/1/94 final report to address the outstanding issues of what constitutes sufficient demand for new pipeline services and how this will be determined.

WG5 asked for FERC's endorsement of its recommendations. "By endorsing the method and outcome proposed by WG5, the Commission will help ensure that the majority of the requirements it places on the industry in any upcoming order in this docket will have been developed by market participants to improve market efficiency, and will therefore be responsive to the needs of the industry as a whole."

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[1] According to WG5, it was deemed inappropriate to hold PI financially responsible for any database errors because the data will be provided by other parties.

PANHANDLE'S NEW STORAGE SUBSIDIARY TO PARTICIPATE IN DEVELOPING NEW STORAGE PROJECT IN MICHIGAN

Panhandle Storage Co., a newly formed subsidiary of Panhandle Eastern Corp., announced on 10/8/93 that it will participate in a partnership to develop a 42 Bcf underground natural gas storage field in Washington Township, Michigan, about 30 miles northeast of Detroit.

The storage project, comprising a partnership between subsidiaries of MCN Investment Corp. (40%), TransCanada PipeLines Ltd. (40%), Union Gas Ltd. (10%) and Panhandle Eastern (10%), will take about two years to complete at a cost of about $120 million. The partners filed an application on 10/7/93 for Michigan PSC approval of the project. MCN Investment will operate the new storage project, which is a conversion of a depleted underground natural gas field originally discovered in 1969. Each of the partners or their affiliates will be storing gas under long-term contracts. The field should be operational for the 1995-1996 heating season.

The Washington Township storage field represents the first storage project for Panhandle Storage.

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In another storage development, Koch Gateway Pipeline Co. (formerly United Gas Pipe Line Co.) announced on 10/12/93 that it will hold an open season for interruptible storage service at its Bistineau storage facility in Louisiana during the week October 15-October 22. Koch Gateway will receive requests for up to 60 Bcf of ISS capacity and 11 Bcf of storage capacity with a corresponding sale of gas in place. The open season is subject to FERC approval to sell Bistineau gas in place.

RECENT DOE DEVELOPMENTS REGARDING LONG-TERM IMPORTS

During the past several months, the Department of Energy's Office of Fossil Energy (OFE) approved several requests by LDCs to import Canadian gas, and by others to import Canadian supply for sale to distributors. In some instances, the applications are a direct result of Order No. 636 restructuring.

For example, in Order Nos. 855 and 856 issued 10/1/93, OFE authorized Wisconsin Public Service Corp. (FE93-93-NG) and Wisconsin Fuel & Light Co. (FE93-94-NG) to import up to 38,459 Mcf/d and 10,398 Mcf/d, respectively, from Canada over the 10-year period 11/1/93-10/31/2003. Wisconsin Public Service and Wisconsin Fuel, currently sales customers of ANR Pipeline Co., agreed under ANR's restructuring plan to purchase directly from Canadian suppliers -- ProGas Ltd. and Western Gas Marketing Ltd. -- their pro rata shares of volumes previously purchased by ANR. Wisconsin Public Service has contracted to purchase up to 11,077 Mcf/d from ProGas and up to 27,382 Mcf/d from WGML, while Wisconsin Fuel will purchase up to 2,995 Mcf/d and 7,403 Mcf/d from the two Canadian suppliers, respectively.

The Wisconsin distributors' gas purchase contracts, which are generally similar, call for a total price comprising (1) a monthly demand charge mostly covering Canadian transportation costs, (2) a monthly commodity charge calculated by adjusting a base price -- $1.80/MMBtu in the ProGas contracts and $1.82/MMBtu in the WGML contracts -- in accordance with changes in specified spot market price indexes relative to April 1993; and (3) a gas inventory charge calculated as a percentage of the adjusted commodity charge depending on the buyer's annual purchase obligation. (The GIC is 1.5% of the adjusted commodity charge for an annual purchase obligation of 100%, and 4.0% for an annual purchase obligation of 50%.) The formula for calculating the commodity charge is subject to renegotiation and to arbitration if the parties are unable to agree on a revised formula. The gas purchase contracts are also subject to minimum take provisions. The two LDCs may elect an annual purchase obligation (based on any increment of 10% between 50% and 100% of their maximum daily contract quantities multiplied by the number of days in the year) and must pay a deficiency charge for purchases less than the elected annual quantities if they are unable to make up

any shortfalls within one year. Under the contracts with WGML, Wisconsin Public Service and Wisconsin Fuel would also incur a deficiency charge if they nominated less than 20% of MDCQ for delivery on any day.

Still pending before OFE are similar applications by Wisconsin Natural Gas Co. (FE93-92-NG) and Wisconsin Power & Light Co. (FE93-101-NG) to import volumes from ProGas and WGML representing their pro rata shares of gas previously purchased by ANR from the two Canadian suppliers. The contracts underlying these imports are nearly identical to those described above.

Earlier, in Order No. 707-A issued 8/10/93, OFE granted an application by Peoples Natural Gas Co., Division of UtiliCorp United Inc. (FE93-70-NG) for amendment of an existing authorization -- permitting imports at Noyes, Minnesota, up to 6,000 Mcf/d on a firm basis and up to 25,000 Mcf/d on an interruptible basis through 11/1/95 -- so as to increase the authorized firm volumes by 3,000 Mcf/d (to 9,000 Mcf/d) and to extend the import term for all volumes by an additional two years through 10/31/97. Peoples explained that it was required to contract for Canadian supplies to serve its franchise communities located on Viking Gas Transmission Co. after Viking converted to a transportation-only pipeline in November 1992.

Other recent long-term import approvals by OFE include the following:

(1) Crestar Energy Marketing Corp. (FE93-83-NG) was authorized by Order No. 849, issued 9/29/93, to import up to 15,000 Mcf/d through 10/31/2001 for sale to Northern States Power Co. (NSP). Crestar's contract with NSP will replace an existing contract under which NSP purchases comparable volumes of Canadian gas from Dome Petroleum Corp. to serve retail customers in the Grand Forks and Fargo areas of North Dakota. The gas sold to NSP will be obtained from supplies produced by Crestar's affiliate, Crestar Energy, in Alberta and British Columbia. The imported gas will be transported from the U.S./Canadian border to NSP by Viking. Until 10/31/93 NSP will pay Crestar a $124,540 monthly demand charge for firm transportation from the wellhead to Emerson, Manitoba, and a monthly commodity charge equal to the spot price of U.S. gas delivered into Northern Natural Gas Co.'s pipeline (as published in *Inside FERC's Gas Market Report*) minus 26¢/MMBtu. After 10/31/93 the demand and commodity charges are subject to annual renegotiation and to arbitration if agreement is not reached. The contract has a minimum seasonal take-or-pay provision: NSP must purchase at least 10,000 Mcf/d during the months November-April and at least 1.09 Bcf during the six-month period May-October. The buyer will have two years to make up any gas paid for but not taken, as well as two years to make up any deficiency volumes left at the end of the contract term.

(2) The Washington Water Power Co. (FE93-57-NG) was authorized by Order No. 822, issued 7/16/93, to import up to a maximum of 61,400 Mcf/d from Canada over a 10-year term. The gas will be purchased from three producers (PanCanadian Petroleum Ltd., AEC Oil & Gas Co. and Amerada Hess Canada Ltd.) under contracts providing for an escalation in deliveries from 36,000 Mcf/d initially to 61,400 Mcf/d by the seventh year. All three contracts provide for a demand charge (covering transportation costs in Canada) and a negotiated commodity rate to be determined annually. All these also contain a minimum annual take requirement ranging from 50% to 85% of the specified MDQs, with WWP subject to a deficiency charge if it does not take the prescribed minimum quantities.

(3) Cascade Natural Gas Corp. (FE93-50-NG) received authority in Order No. 810, issued 6/22/93, to import up to 5,000 MMBtu/d at Sumas, Washington through 10/31/96. The gas will be purchased from Canadian Hydrocarbons Marketing Inc. (CHMI) at a price including: commodity and demand tolls for transportation on Westcoast; a commodity charge of $1.08/MMBtu as of 11/1/90; a supply reservation fee of 30¢/MMBtu as of 11/1/90; and a fuel gas charge to reimburse Westcoast for gas consumed in transporting the volumes purchased by Cascade. (Cascade is currently paying CHMI a total price of $1.64/MMBtu.) The commodity charge and reservation fee are subject to annual redetermination. Cascade has no obligation to purchase a minimum daily quantity, but it must pay

the reservation fee each month regardless of the amount of gas purchased. Also, CHMI may reduce the daily contract quantity if Cascade takes less than 55% of the contract quantity in a year.

(4) Granite State Gas Transmission Inc. (FE93-85-NG) was authorized by Order No. 857, issued 10/5/93, to import up to 6,036 MMBtu/d of Canadian gas through 10/31/2006 for resale to Granite State's two affiliated distribution company customers, Bay State Gas Co. and Northern Utilities, Inc. Granite State will purchase the gas from Direct Energy Marketing Ltd. at a total price including monthly demand charges and monthly commodity charges paid by Direct Energy for transportation on Canadian pipelines, a compressor fuel charge, an energy charge, and 10¢/MMBtu (Canadian). The energy charge is set at a base price of $1.004/MMBtu (U.S.), indexed monthly according to changes in the New England Power Pool (NEPOOL) average fossil fuel cost. In June 1993, the average price of gas imported under this contract was $2.62/MMBtu (U.S.).

Beginning with the third contract year, Granite State will be subject to an 80% minimum annual take obligation. Direct Energy may market gas not taken by Granite State to other purchasers, in which case Granite State would receive a credit toward its minimum volume obligation.

* * * * *

In another development stemming from Order No. 636 restructuring, OFE on 9/30/93 terminated authorizations held by (1) Texas Eastern Transmission Corp. (FE87-37-NG) to import up to 75,000 Mcf/d from ProGas Ltd. through 10/31/2000; and (2) Texas Eastern, Northeast Energy Associates and North Jersey Energy Associates (FE89-26-NG) to import a combined average of 101,000 Mcf/d from ProGas.[1] Early this year, Texas Eastern and ProGas reached an overall settlement providing for, among other things, release by ProGas Ltd. of Texas Eastern's purchase obligations under two supply contracts (and early expiration of those contracts effective 4/1/93) and assignment of Texas Eastern's upstream capacity rights on CNG Transmission and Great Lakes Gas Transmission to ProGas U.S.A. FERC approved the assignments on 3/31/93, noting a savings of more than $120 million in upstream pipeline demand charges (and hence transition costs) to Texas Eastern. (See REPORT NO. 1921, pp22-23.)

To replace one of Texas Eastern's two gas purchase contracts, ProGas U.S.A. (FE93-87-NG) applied on 9/2/93 for authority to import 75,000 Mcf/d from ProGas Ltd. at Emerson, Manitoba over a 10.5-year term for sale to Consumers Power Co. The gas will be delivered by Great Lakes to Consumers Power at a new delivery point near Chippewa, Michigan. The contract with Consumers Power is divided into two phases. Under Phase I, covering the period April-October 1993, Consumers Power must take 100% of the contract volume of 75,000 Mcf/d and pay a fixed price of $1.72/MMBtu. During Phase II, which extends from 11/1/93 until 10/31/2003, Consumers Power will have a 50% minimum monthly purchase obligation and a 70% minimum annual purchase obligation, and will pay a monthly demand charge (75¢ times the DCQ times the number of days each month) and a monthly commodity charge ($1.55/MMBtu initially, adjusted annually according to changes in Consumers Power's WACOG, with a further monthly adjustment factor depending on the month involved).

Other pending long-term applications before OFE include requests by:

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[1] A 1986 contract committing Texas Eastern to purchase 101,000 Mcf/d from ProGas was amended in 1988 to relieve Texas Eastern from most of this commitment and to provide for sale by ProGas instead to the two cogeneration users. The amendments provided that Texas Eastern would purchase 29,000 Mcf/d and the two cogeneration plants 72,000 Mcf/d (36,000 Mcf/d each). However, Texas Eastern also agreed to certain "backstop" obligations (in the event the two cogen plants did not purchase the specified quantities) as an integral part of the arrangement to reduce its contract demand.

(1) The Consumers' Gas Co. Ltd. (FE93-88-NG) to export up to 66,000 Mcf/d for its own system supply over a 15-year period. The proposed export will support Consumers' participation in the Intercoastal Pipe Line project, a joint venture of Interprovincial Pipe Line Systems and ANR Pipeline Co., which includes a 156.6-mile 20- to 24-inch interprovincial pipeline extending from an interconnection with ANR at the international border near Corruna, Ontario to interconnections with Consumers' Tecumseh storage complex and distribution system near Toronto, Ontario. Intercoastal will be anchored by a 15-year firm transportation agreement with Consumers' providing for 110,000 Mcf/d in the first contract year, 133,000 Mcf/d in the second year, 150,000 Mcf/d in the third year, and 175,000 Mcf/d in the fourth year and thereafter.

Consumers' purchases natural gas for export from a variety of U.S. producers, brokers and other suppliers. At present, it has outstanding purchase contracts with Coastal Gas Marketing Co., CoEnergy Ventures Inc., Amoco Energy Trading Corp., Natural Gas Clearinghouse, Inc., Seagull Marketing Services and Tarpon Gas Marketing Ltd. Consumers' current gas purchase agreements with U.S. suppliers typically have an initial term of six months to one year, and then continue on a month-to-month basis thereafter. Consumers' anticipates executing agreements for firm U.S. supplies with initial primary terms of one to five years.

(2) Northern Minnesota Utilities (FE93-84-NG) to amend an existing authorization in order to increase imports from ProGas Ltd. from 10,000 to 22,000 Mcf/d through 5/1/2001. The gas will be imported by NMU for resale purposes and for system supply.

(3) The Montana Power Co. (FE93-96-NG) to continue imports of 1,060 Mcf/d from Canadian-Montana Pipeline Co. for another 11 years 1/1/94-12/31/04.

SUMMARY OF RECENT BLANKET IMPORT/EXPORT AUTHORIZATIONS GRANTED BY DOE

The table below summarizes two-year blanket import/export authorizations granted by DOE's Office of Fossil Energy (OFE) during the four-month period June-September 1993. As in the past, all of the authorized imports/exports are subject to quarterly reporting requirements.

The bulk of the blanket authorizations granted during the June-September period involve trade with Canada. However, OFE also approved several requests to export/import gas to and from Mexico. In general, the Canadian gas applications take anywhere from a week to a month to be approved, while the Mexican gas applications require from two to four months. This reflects Section 201 of the Energy Policy Act of 1992 which provides that natural gas imports or exports from or to a nation with which the United States has a free trade agreement in effect (requiring national treatment for trade in natural gas) shall be deemed consistent with the public interest and granted without modification or delay.

Many of the newly granted authorizations shown in the table below are renewals of two-year authorizations which have already expired or will soon expire.

Two blanket authorization requests of particular interest were filed on 9/20/93 by Pacific Gas & Electric Co. to import a maximum volume exceeding 1.1 Tcf over a two-year period. Of this total, PG&E would import up to 305 Bcf for use in its electric generating plants and up to 790 Bcf for resale to end users, LDCs and municipalities in northern and central California. The two requests were both approved on 9/30/93.

BLANKET IMPORT/EXPORT AUTHORIZATIONS GRANTED					
DOE/OFE Authority			Two-Year Maximum		
Order No.	Date Issued	Importer/Exporter Docket No.	Import Volume	Export Volume	Comments
699-A	6/25/93	Vector Energy (U.S.A.) (92-118-NG)	44 Bcf		Amendment of prior order increasing maximum import volume from 30 Bcf to 44 Bcf.
807	6/2/93	Husky Gas Marketing (93-51-NG)		18 Bcf	Exports to Canada.
808	6/8/93	Inland Natural Gas Marketing (93-52-NG)	50 Bcf	50 Bcf	Imports/exports from and to Canada.
809	6/16/93	Cascade Natural Gas (93-48-NG)	56 Bcf		Imports from Canada.
811	6/24/93	Meridian Marketing & Transmission (93-35-NG)		36 Bcf	Exports to Mexico.
812	6/24/93	American Hunter Exploration (93-12-NG)		150 Bcf	Exports to Mexico, primarily to PEMEX.
813	6/24/93	El Paso Gas Marketing (93-39-NG)		75 Bcf	Exports to Mexico.
814	6/25/93	Western Gas Resources (93-26-NG)	73 Bcf	73 Bcf	Imports/exports from and to Mexico.
815	6/25/93	Great West Energy Ltd. (93-60-NG)	40 Bcf		Imports from Canada.
816	6/30/93	Northstar Energy Corp. (93-54-NG)	7.3 Bcf		Imports from Canada.
817	6/30/93	Texaco Gas Marketing (93-45-NG)		120 Bcf	Exports to Mexico.
818	7/13/93	Iroquois Energy Management (93-62-NG)	10 Bcf		Imports from Canada.
819	7/13/93	Nortech Energy Corp. (93-65-NG)	40 Bcf	40 Bcf	Imports/exports from and to Canada.
820	7/13/93	Brymore Energy Inc. (93-61-NG)	200 Bcf	200 Bcf	Imports/exports from and to Canada.
821	7/14/93	Sonat Marketing Co. (93-53-NG)	100 Bcf		Imports from Canada.
823	7/29/93	Jonan Gas Marketing (93-68-NG)	----------100 Bcf----------		Imports/exports up to combined total of 100 Bcf from/to Canada.
824	7/29/93	Conoco Inc. (93-72-NG)	----------50 Bcf----------		Imports/exports from and to Canada, and imports from any international market, up to combined total of 50 Bcf.
825	7/30/93	Tennessee Gas Pipeline (93-55-NG)		100 Bcf	Exports to Mexico.
826	7/30/93	Bay State Gas Co. (93-76-NG)	40 Bcf		Imports from Canada.
827	7/30/93	Northern Utilities Inc. (93-77-NG)	15 Bcf		Imports from Canada.
828	7/30/93	Texas International Gas & Oil (93-56-NG)		29.2 Bcf	Exports to Mexico.
829	8/3/93	Development Associates (93-71-NG)	48 Bcf		Imports from Canada.

830	8/9/93	Natural Gas Clearinghouse (93-74-NG)	400 Bcf	130 Bcf	Imports/exports from and to Canada, and imports of LNG from any foreign country.
831	8/9/93	Utility-2000 Energy Corp. (93-80-NG)	----------60 Bcf----------		Imports/exports up to aggregate of 60 Bcf from and to Canada.
832	8/10/93	Midcon Texas Gas Services (91-31-NG) (91-49-NG)			Amendment of Order No. 521 (authorizing 146 Bcf of exports to Mexico) and Order No. 562 (authorizing 150 Bcf of imports from Canada) to reflect change of name from UTRADE Gas Co. To date, no imports or exports have occurred.
833	8/11/93	Sonat Marketing Co. (93-43-NG)		100 Bcf	Exports to Mexico.
834	8/13/93	Tennessee Gas Pipeline (93-79-NG)		200 Bcf	Exports to Canada.
835	8/13/93	Mobil Natural Gas (93-67-NG)		200 Bcf	Exports to Canada.
836	8/17/93	Vesta Energy Co. (93-82-NG)	100 Bcf	100 Bcf	Imports/exports from and to Canada.
837	8/25/93	Coenergy Trading Co. (90-113-NG) (91-120-NG) (93-28-NG)			Amendment of Order Nos. 504, 600 and 788 (authorizing imports and exports from and to Canada) to reflect change in name from CoEnergy Ventures Inc.
838	8/27/93	Conoco Inc. (93-63-NG)	----------50 Bcf----------		Imports/exports from and to Mexico, and exports of LNG to any foreign country, up to combined total of 50 Bcf.
839	8/31/93	Bonus Gas Processors (93-59-NG)	220 Bcf	220 Bcf	Imports/exports from and to Canada.
840	8/31/93	AIG Trading Corp. (93-73-NG)	200 Bcf	200 Bcf	Imports/exports from and to Mexico.
841	9/24/93	Amoco Energy Trading (93-58-NG)		146 Bcf	Exports to Mexico.
842	9/24/93	Associated Natural Gas (93-64-NG)		200 Bcf	Exports to Mexico.
843	9/24/93	Mobil Natural Gas (93-69-NG)		200 Bcf	Exports of natural gas to Mexico, and exports of LNG to any foreign country.
844	9/24/93	Natural Gas Clearinghouse (93-75-NG)	200 Bcf	200 Bcf	Imports/exports from and to Mexico, including LNG exports to any foreign country.
845	9/24/93	Midland Cogeneration Venture (93-81-NG)	20 Bcf		Imports from Canada.
846	9/29/93	Valero Industrial Gas (93-78-NG)	----------300 Bcf----------		Imports/exports from and to Mexico up to combined total of 300 Bcf.
847	9/30/93	Wisconsin Gas Co. (93-91-NG)	200 Bcf		Imports from Canada.
848	9/30/93	Nortech Energy Corp. (93-66-NG)	40 Bcf	40 Bcf	Imports/exports from and to Mexico.
850	9/30/93	Tennessee Gas Pipeline (93-89-NG)	200 Bcf		Imports from Canada.
851	9/30/93	Pacific Gas & Electric. Electric Supply Business Unit (93-99-NG)	305 Bcf		Imports from Canada for use in electric generating plants.
852	9/30/93	Pacific Gas & Electric. Gas Supply Business Unit (93-100-NG)	790 Bcf		Imports from Canada for purposes of resale.
853	9/30/93	Vermont Gas Systems (93-98-NG)	20 Bcf	20 Bcf	Imports/exports from and to Canada.

FERC ELIMINATES REGULATIONS COVERING OCSLA CAPACITY REALLOCATION PROGRAM

In Order No. 559 (RM93-8) issued 10/4/93, FERC eliminated existing regulations governing allocation of natural gas pipeline capacity on the Outer Continental Shelf, as well as certain related regulations pertaining to pipelines' OCS operations which have been rendered obsolete by Order No. 636.

Background

The regulations at issue here were adopted in Order No. 509 (RM88-15), issued 12/9/88, to implement Section 5 of the Outer Continental Shelf Lands Act (OCSLA) requiring open access, nondiscriminatory transportation of all gas on the OCS. Order No. 509 granted a blanket transportation certificate to every interstate pipeline hauling OCS gas, and directed all such pipelines to file new rates and tariff provisions by 3/1/89 reflecting the blanket certificates.

In addition, Order No. 509 required (1) all OCS pipelines to conduct an "open season" to allocate uncommitted firm capacity and any firm capacity voluntarily relinquished by existing shippers; (2) those OCS pipelines not already holding a blanket transportation certificate to conduct an "open season" to allocate interruptible capacity using any nondiscriminatory means acceptable for onshore blanket certificate transportation; and (3) all OCS pipelines to establish procedures for voluntary reallocation of firm transportation capacity in the event an existing shipper desired to relinquish any of its firm capacity rights after the "open season" period. If more than one shipper wished to acquire the capacity sought to be relinquished, FERC provided that the voluntary reallocation proceed on a first-come, first-served, pro rata or any other nondiscriminatory basis consistent with the OCS pipeline's transportation rate schedule on file with the Commission. The OCS blanket certificates granted by Order No. 509 included authority for abandonment of transportation services necessary to implement reallocation of capacity, including individually-certificated services to the extent the shipper voluntarily relinquished the firm capacity.

FERC reaffirmed the Order No. 509 regulations, subject to relatively minor modifications, in Order No. 509-A issued 2/21/89. Subsequently, on 8/14/92, the D.C. Circuit largely upheld the Order No. 509/509-A regulations, but remanded three separate orders applying those regulations to Tennessee Gas Pipeline Co. (RP89-84). The Tennessee orders -- which involved the treatment of transactions extending from OCS receipt points to delivery points beyond the first interconnection on the shoreward side of the OCS -- were challenged to the extent they required an OCS interstate pipeline to request abandonment of transportation service through non-OCS segments of the pipeline, to serve a new shipper under its onshore open access blanket certificate, and to charge the new shipper the generally applicable open access rate. The Court agreed with Tennessee that FERC lacked authority to order abandonment of existing onshore transportation service prior to expiration of the underlying contract. (See REPORT NOS. 1702, pp2-9; 1711, pp7-13; 1890, pp16-18.)

FERC issued a notice of proposed rulemaking on 4/21/93 to remove the Order No. 509 capacity allocation provisions as redundant in view of the Order No. 636 capacity release program applicable to all interstate pipeline transportation, offshore and onshore. But, the Commission noted, so long as the Order No. 509 provisions continue to exist, there is room for conflict over which program applies to OCS transactions. Therefore, the Commission proposed to eliminate the OCSLA capacity reallocation program in order to remove this conflict and further the goal of a uniform capacity release program.

The Commission also proposed to remove the Order No. 509 regulations which required the filing of Part 284 transportation rates for service under the OCS blanket certificates. Since all OCS interstate pipelines now have rates on file for transportation service under a blanket certificate, the Commission said the Order No. 509 regulations are no longer needed. (See REPORT NO. 1924, pp16-18.)

In a companion order issued concurrently with the rulemaking notice, FERC concluded that the proposed rule should resolve the matters remanded by the D.C. Circuit and eliminate Tennessee's concerns. Specifically, the Commission explained, removal of the OCS capacity allocation program (including the Order No. 509 abandonment authority) -- coupled with tariff provisions in Tennessee's Order No. 636 compliance filing that individually certificated Section 7(c) transportation services priced at rolled-in rates will be conducted under Tennessee's Part 284 firm transportation rate schedule (unless prohibited by contract) and that incrementally-priced, individually certificated transportation may be converted to Part 284 firm transportation -- should resolve the difficulties raised by Tennessee. If not, Tennessee should so advise in its comments on the rulemaking proposed in RM93-8.

Order No. 559

In Order No. 559, the Commission granted certain requests by High Island Offshore System and U-T Offshore System for clarification. First, FERC clarified that elimination of the Order No. 509 capacity allocation and related regulations -- which have become superfluous -- do not affect the validity of the blanket certificates issued in Order No. 509. Second, the Commission clarified that capacity relinquishments implemented under the Order No. 509 regulations remain authorized despite discontinuation of those regulations. Existing Order No. 509 capacity allocations may remain effective for the term agreed upon between the parties. However, the Commission added, once a pipeline's Order No. 636 capacity release program goes into effect, it must post notice of all preexisting Order No. 509 capacity allocations on its electronic bulletin board.

Further, as requested by HIOS and U-TOS, FERC provided for termination of Order No. 509 capacity allocation programs on 11/1/93, a date when most interstate pipelines will have Order No. 636 capacity release programs in effect. New capacity allocations may be made under the Order No. 509 programs until that time. If the November 1 effective date interferes with ongoing transactions for the few pipelines whose Order No. 636 tariffs become effective after November 1, they may notify the Commission and request appropriate relief.

Other than HIOS and U-TOS, Tennessee was the only party to comment on the proposed rulemaking. Tennessee said its difficulties with the Order No. 509 capacity allocation program would be resolved by the proposed rule only if the Commission approved the procedure set forth in Tennessee's restructuring docket (RS92-23) for individually certificated shippers to convert to Part 284 firm transportation.

FERC essentially opted to leave this matter to Tennessee's restructuring proceeding. However, the Commission commented, it appears that Tennessee has "come full circle on this issue." While Tennessee previously resisted abandoning individually certificated service and providing new service from the OCS under a Part 284 blanket transportation certificate, it now argues that Part 157 individually certificated services must be converted to Part 284 service to remove the potential for discriminatory treatment among similarly situated shippers and to prevent Part 157 shippers from avoiding their fair share of Order No. 636 transition costs, among other reasons. The Commission declined to address Tennessee's position because Part 157 services may be converted to Part 284 service only with consent of the pipeline and its customers. It therefore encouraged Tennessee to negotiate directly with its customers regarding conversion to Part 284 service and "thereby avoid the potential for the types of abuses Tennessee perceives."

Further, the Commission noted, it is unclear from Tennessee's comments how the specifics of a conversion procedure undertaken within the context of an Order No. 636 restructuring proceeding relate to rescission of the Order No. 509 capacity allocation program. However, it is unnecessary to consider this matter here. Instead, the specifics of the conversion procedure must be addressed in Tennessee's restructuring docket.

SOCALGAS ENTERS AUTOMOTIVE FLEET INDUSTRY THROUGH NGV JOINT VENTURE

Southern California Gas Co. will create a multi-million dollar manufacturing facility in East Los Angeles, called Ecotrans, for the production of natural gas powered vehicles (NGVs). Ecotrans will specialize in the production of new NGVs, the conversion of conventionally-fueled vehicles, and NGV research and development. Joining SoCalGas are PAS Inc., of Troy, Michigan; NGV Systems Inc. of Long Beach, California; and 4E Technologies of Los Angeles.

One venture, Ecotrans Vehicle Industries (EVI), will "upfit" new General Motors vehicles to run on natural gas. It will operate in partnership with PAS Inc., a specialty vehicle original equipment manufacturer (OEM). EVI will receive four models of GM vehicles directly from the factory: the full-size passenger and cargo van known as the "G" van, the multi-purpose step-in van referred to by GM as the "P" chassis, the medium duty truck and the full-size Sierra pickup. Assembly will require addition of natural gas tanks, fuel delivery systems and electronic diagnostic components. The vehicles will carry a full OEM warranty. Some will be sold and serviced by dealers and others marketed to fleet owners by 4E Technologies, an auto industry sales and consulting firm.

The second Ecotrans Venture will be NGV Ecotrans Technology Center, which will convert new and existing conventionally fueled vehicles to natural gas operation. This business will be opened and operated by SoCalGas and NGV Systems Inc.

The twin facilities are expected to upfit or convert some 5,000 vehicles by the end of 1994, with a production goal of 17,000 vehicles manufactured by December 1996. The operation will create jobs and payroll in an economically disadvantaged area of Los Angeles. If vehicle sales increase as anticipated, the Ecotrans Center is expected to employ more than 100 workers by the end of 1994.

SoCalGas' $8 million contribution to this venture is funded $5 million from shareholders and $3 million from ratepayers. It is supporting development of the NGV refueling infrastructure as well. The thirty-fourth refueling site was opened this week near Riverside, California at a Shell Oil Co. service station. By 1996, SoCalGas expects to have over 150 NGV refueling sites in service.

"We anticipate that the recognized performance of NGVs, their economy of operation and the need to meet federal and state clean air requirements will result in more than 300,000 NGVs on the road in our Southern California service area by the turn of the century," said Warren Mitchell, SoCalGas president and incoming president of Natural Gas Vehicle Coalition.

COMMISSIONER HOECKER NAMES LINDIL FOWLER AS LEGAL ADVISOR

On 10/13/93 FERC Commissioner James J. Hoecker named Lindil C. Fowler, Jr. to his personal staff as a legal advisor on electric and natural gas issues.

Fowler was General Counsel of the Oklahoma Corporation Commission from 1985 to 1993, directing legal oversight of Oklahoma's oil and gas industry, public utilities (gas, electric, water and telecommunications), intrastate motor carrier transportation of freight and passengers, and federally-mandated environmental programs.

He began his legal career in Washington, D.C. at the General Accounting Office (1975-1981), adjudicating claims involving government contracts and federal employees.

Fowler is a Native American (Chickasaw Tribe) and holds a B.A. degree in political science from Southwestern Oklahoma State University and a law degree from the University of Oklahoma College of Law.

NORTHWEST NATURAL CEO ELECTED AGA PRESIDENT FOR 1993-1994

On 10/10/93 Robert L. Ridgley, President and CEO of Northwest Natural Gas Co. (Portland, Oregon), was elected Chairman of the American Gas Association for 1993-1994 at AGA's annual conference. Ridgley, 58, was a practicing attorney until 1984, when he joined Northwest Natural as Executive Vice President. One year later, he became President and CEO.

Robert B. Catell, President and CEO of The Brooklyn Union Gas Co., was elected AGA First Vice Chairman and George A. Davidson, Jr., Chairman and CEO of Consolidated Natural Gas Co., Second Vice Chairman.

CORRECTION: GRI BUDGET APPROVAL

In REPORT NO. 1947 (September 30, 1993), p18, it was stated that FERC, on 10/19/93, approved the Gas Research Institute's R&D budget for 1994. The date of FERC's approval is incorrect. The Commission approved GRI's latest R&D plan (RP93-140) by Opinion No. 384 issued 10/5/93.

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