

Report of the Committee on International Energy Transactions

The following is an overview of major international energy developments which occurred in the United States and Canada during 1990.

I. DEVELOPMENTS IN THE UNITED STATES—NEW PIPELINE PROJECTS

A. *Iroquois Gas Transmission System, L.P.*

1. FERC Developments

On November 14, 1990, in Opinion No. 357,¹ the Federal Energy Regulatory Commission (FERC or Commission) authorized the construction and operation of Iroquois Gas Transmission System (Iroquois), a \$585 million pipeline which, as proposed, involves the firm transportation of up to 645,800 Mcf per day of primarily Canadian gas supplies to various local distribution companies, three cogeneration customers, and one electric generation customer. Iroquois is authorized to deliver a portion of the gas directly to some customers and to deliver the remaining volumes to Tennessee Gas Pipeline Company (Tennessee), Algonquin Gas Transmission Company (Algonquin), and Texas Eastern Transmission Corporation (Texas Eastern) for distribution to the remaining Iroquois customers. Moreover, the Commission largely upheld an earlier order² and the subsequent findings of fact of an administrative law judge,³ and determined that the rates, as modified by the Commission, were just and reasonable.

In particular, the Commission authorized: (1) Iroquois to construct and operate a new 369.4 mile pipeline extending from the international border near Waddington, New York, through Eastern New York and Western Connecticut, across Long Island South to an interconnection with Long Island Lighting Company near South Commack, New York; (2) long-term firm transportation service by Iroquois of up to 422,900 Mcf per day for various distributor and cogeneration customers; (3) Tennessee to construct certain pipeline loops and laterals required on its existing system in order to render its share of the proposed service; and (4) long-term firm transportation by Tennessee of up to 162,795 Mcf per day for various shippers.⁴ The Commission also issued Iroquois a Presidential Permit to construct, operate, maintain, and connect certain natural gas facilities at the international boundary between the United States and Canada. Additionally, certificates were issued to the New York shippers which authorized certain exchange transportation arrangements in their service areas for a limited term of twenty years.

In approving the Iroquois Project, the Commission rejected arguments that the volumes were not required to meet the foreseeable needs of customers

1. Iroquois Gas Transmission Sys., L.P., 53 F.E.R.C. ¶ 61,194 (1990).
2. Iroquois Gas Transmission Sys., L.P., 52 F.E.R.C. ¶ 61,091 (1990).
3. Iroquois Gas Transmission Sys., L.P., 52 F.E.R.C. ¶ 63,031 (1990).
4. 53 F.E.R.C. ¶ 61,194, at 61,779-80.

in the northeastern United States and that the project would promote an unfair rate advantage, favoring Canadian gas over domestic supplies. Instead, the Commission determined that the market projections provided by Iroquois were reasonable, and that Iroquois would, in fact, serve an incremental market and would not displace significant domestic supplies. Furthermore, the Commission declined to modify the private contracts between shippers and Canadian suppliers to mitigate the alleged Canadian gas rate advantage, explaining that such action would violate the Free Trade Agreement.

While the Commission ordered Iroquois and Tennessee to be placed "at risk for any under recovery of costs resulting from any shortfall in volumes, no matter what the cause,"⁵ it allowed Tennessee to implement a hybrid rate design which would provide it the opportunity to recover its construction costs. This would be accomplished by permitting Tennessee to reduce the fixed costs recovered through its commodity charge under the modified fixed variable rate design method from approximately fifty percent to twelve percent and concomitantly increased fixed costs recovery through the demand charge from about fifty to eighty-eight percent. Tennessee had asked for a one hundred percent demand charge rate for firm transportation of Iroquois gas.

Numerous requests for rehearing and stay of Opinion No. 357 were filed with the Commission. Order No. 357-A, issued February 4, 1991, generally denied the requests for rehearing or stay. However, the Commission did grant Tennessee's rehearing to the extent of authorizing rates that reflect a five percent depreciation rate.⁶ Tennessee has sought rehearing of certain facilities-depreciation conditions specified in the Iroquois order.

On December 19, 1990, Iroquois filed an application with the Commission to amend its certificate issued on November 14, 1990, proposing to change the accounting treatment for the Iroquois line. In its application, Iroquois explained that the proposed accounting modifications were required to reflect expected delays in the construction of related pipeline expansion facilities by TransCanada.

2. Department of Energy, Office of Fossil Energy Developments

In other Iroquois developments, in Opinion No. 368-A,⁷ the Department of Energy, Office of Fossil Energy (DOE/FE) granted final authorization, pending completion of environmental review, to eighteen Northeast distributors to import up to 352,100 Mcf per day of Canadian gas supplies through Iroquois facilities that will be constructed pursuant to the authorization issued in Opinion No. 357. The majority of these gas supplies will be imported at a new international border crossing near Waddington, New York, for transportation by Iroquois. Approximately 10,000 Mcf per day will be imported by National Fuel through Tennessee's border facilities at Niagara Falls, New York.⁸

5. 53 F.E.R.C. ¶ 61,194 at 61,721.

6. 54 F.E.R.C. ¶ 61,103, at 61,364.

7. Brooklyn Union Gas Co., DOE/FE Opinion and Order No. 368-A (Nov. 15, 1990).

8. Great Lakes Gas Transmission Co., DOE/FE Opinion and Order No. 425 (Sept. 29, 1990).

In addition, Granite State Transmission was authorized to import up to 35,000 MMBtu per day on a firm basis and up to 14,000 MMBtu per day on an interruptible basis over a fifteen-year period, beginning September 1, 1991.⁹ The gas will be transported from the international border by Iroquois, Tennessee, and Algonquin to various connections with Granite State in Massachusetts. Granite State will use the gas to meet the growing requirements of its two jurisdictional customers, Bay State Gas Company and Northern Utilities.

B. Niagara Import Point System Projects

Phase III of the Niagara Import Point System (NIPS) projects was approved by the Commission on September 13, 1990.¹⁰ In its order, the Commission authorized each of the seven participating interstate pipelines to complete its respective portion of the overall project, subject to certain rate and environmental conditions and the acquisition of final long-term import licenses from the DOE/FE.¹¹ The overall NIPS projects consist of 543.3 miles of pipeline looping and 61,300 horsepower of additional compression, which will be used to provide firm transportation service of 346,000 Mcf per day of Canadian natural gas and 45,000 Mcf per day of domestic gas. Except for 31,500 Mcf per day of gas reserved for interstate pipeline system supply, the remaining gas to be transported under Phase III is owned by third-party shippers. Upstream of the Niagara import point, Great Lakes has proposed to provide firm transportation service of up to 417,500 Mcf per day of Canadian natural gas to TransCanada, of which 285,000 Mcf per day is scheduled for transshipment to NIPS customers. The rates for each pipeline sponsor approved by the Commission are initial rates which, consistent with prior orders involving NIPS project certificates, are incremental rates. The Commission rejected Tennessee's request for rates based on 100 percent demand charges and, instead, directed Tennessee to use a modified fixed variable rate design.

Earlier in the year, on May 2, 1990, the Commission issued an order authorizing certificates for Phase II of the NIPS projects. Phase II includes the construction and operation of a 31.4 mile portion of Tennessee's existing Niagara Spur Loop Line, which extends from Tennessee's Niagara River interconnection with TransCanada to a point on Tennessee's system in Erie County, New York.¹² In this order, the Commission rejected Tennessee's proposal to develop consolidated incremental rates covering all costs and services connected with three other major Northeast United States pipeline projects, the construction of which had not yet been approved or even considered. Instead, Tennessee was ordered to base its incremental rates on costs related only to its Phase II NIPS facilities. These costs must be covered through the modified fixed variable rate design method.¹³

9. Granite State Transmission, Inc., DOE/FE Opinion and Order No. 449 (Nov. 15, 1990).

10. Tennessee Gas Pipeline Co., 52 F.E.R.C. ¶ 61,257 (1990).

11. On September 29, 1990, DOE/FE issued Order No. 425 approving final import/export authority to various projects considered part of the certificated Phase III NIPS projects.

12. Tennessee Gas Pipeline Co., 51 F.E.R.C. ¶ 61,113 (1990).

13. National Fuel Gas Supply Corp., 48 F.E.R.C. ¶ 61,121 (1989). Phase I of the NIPS projects was

C. Empire State Pipeline

The Empire State Pipeline project, filed with the Commission in December 1989,¹⁴ involves the construction of a 155 mile pipeline with a design capacity of 150,000 Mcf per day and a peak day delivery capacity of 270,000 Mcf. Empire is co-owned by subsidiaries of The Coastal Corporation, Rochester Gas and Electric Corporation, and Union Enterprises Ltd. As proposed, the pipeline will commence at the international border between Canada and the United States near Grand Island, New York, at an interconnection with TransCanada Pipelines Ltd. and will terminate in the vicinity of Syracuse, New York. According to Empire, its facilities will be used to transport imported natural gas originating both in the United States (in states other than New York) and in Canada for consumption within New York. During 1990, the Empire project precipitated a series of competing application filings with the Commission by National Fuel Gas Supply Corporation, CNG Transmission Corporation, and Tennessee Gas Pipeline.

In late February and March 1990, National Fuel filed a series of applications¹⁵ which, according to National Fuel, together constitute a bona fide, mutually exclusive alternative to the westernmost segment of the Empire project. As proposed, National Fuel's alternative would extend 32.7 miles from Grand Island, New York, to Royalton, New York, and assertedly would be less costly as well as environmentally superior to the comparable Empire facilities. Under a settlement reached with Empire, however, on October 9, 1990, National Fuel filed notices with the Commission seeking to withdraw its applications.

Pursuant to its settlement with Empire, National Fuel filed an amended application on November 6, 1990,¹⁶ in which it proposes to extend certain facilities which would connect with Empire in two locations and enable it to participate in two transportation arrangements with Empire. In particular, National Fuel seeks authorization to deliver 100,000 Mcf of gas to Empire at Wheatfield, New York, which will be redelivered to National Fuel by Empire at Grand Island for consumption in the northern Buffalo area. In addition, National Fuel proposes to receive approximately 38,000 Mcf per day from Empire at Grand Island which National Fuel will transport under a forward haul arrangement for delivery to three cogeneration customers in New York.

On August 14, 1990, CNG filed a certificate application seeking authorization to construct certain facilities which would provide a competitive alternative to the Empire project (CNG's Empire alternative).¹⁷ CNG's proposal is designed to replace the easternmost 122 miles of the Empire project by means of the construction of 68.7 miles of pipeline looping and compression facilities which would interconnect with National Fuel at Clarence, New

the subject of this order. The Commission authorized the construction and commencement of storage service contemplated under the group of projects that resulted from a settlement offer filed November 21, 1988.

14. Nos. CP90-316-000 and CP90-317-000.

15. Nos. CP90-854-000, CP90-920-000, CP90-967-000, and CO90-968-000 (National's alternative).

16. No. CP90-854-000.

17. No. CP90-1989-000, 56 FERC ¶ 61,050 (1991) (final disposition of this application).

York. This proposed construction included 52.6 miles of pipeline along existing rights-of-way and 16.1 miles along new rights-of-way. Under its proposal, CNG is seeking authorization to transport 235,104 dekatherms of gas per day for the Empire shippers and 24,467 dekatherms per day for two of the three cogeneration customers proposed to be served by National Fuel.

Pursuant to an amended application filed on January 7, 1991, CNG proposes to extend certain pipeline facilities an additional 7.5 miles. The extension would interconnect CNG's Empire alternative with Tennessee Gas, beginning at a point at Pendleton, New York, instead of Clarence, New York, as had been originally proposed. CNG claims that its alternative and approval of either the National Fuel Alternative or the Tennessee Gas proposal (discussed below) will prove to be a superior alternative, both economically and environmentally, to that of Empire.

On December 20, 1990, Tennessee Gas filed an application with the Commission which it asserts is a mutually exclusive alternative to the westernmost 25.5 miles of Empire's proposed facilities.¹⁸ In its application, Tennessee Gas proposes to use its existing Niagara Falls import point on the United States-Canadian border near Lewiston, New York, to deliver 256,000 Mcf of gas per day on a firm basis in the winter and 151,000 Mcf of gas per day in the summer on its Niagara Spur Line and its Niagara Spur Loop Line to an interconnection with Empire at Pendleton, New York. These deliveries would be accomplished through an expansion on the Niagara Spur Loop Line involving additional compression at a cost of \$8.5 million which, according to Tennessee Gas, could be built at a \$29 million savings relative to the comparable facilities proposed under the Empire project.

On December 7, 1990, the Commission announced that it will prepare an environmental assessment relating to Empire and its alternatives, and asked for public comments to be filed by January 9, 1991.

II. GENERAL DEVELOPMENTS IN CANADA

In 1990, Canadian federal and provincial regulatory bodies took steps to ease restrictions on bilateral gas trade in keeping with the spirit of the Free Trade Agreement. British Columbia eliminated its border price test and mandatory surplus test which had hindered exports from the province. The National Energy Board (NEB or Board) eliminated its benefit/costs test, resulting in the approval of previously denied export applications. It also amended its export impact assessment filing requirements, thereby lessening the regulatory burden on export applicants. Finally, the NEB, in the context of TransCanada PipeLines Ltd.'s (TCPL) 1991/1992 facilities application, reaffirmed the appropriateness of rolled-in tolls on the TCPL system, rejecting adoption of proposals that would have increased the transportation cost to new export markets.

18. No. CP91-724-000 (Tennessee's Niagara alternative), 56 FERC ¶ 61,050 (1991) (final disposition of this application).

A. *British Columbia*

To enhance the marketability of its gas in Canadian and U.S. markets, British Columbia eliminated its border price and mandatory surplus tests and agreed to allow flexible reserves dedication. The border price test prohibited the removal of natural gas from the province at a price less than the price charged to British Columbia users for similar service. On finding that sales arrangements in the export and domestic markets are not directly comparable, due to higher processing and transportation costs for domestic sales and variations in the floor price at the border not attributable to the cost of gas, the test was abolished in favor of market negotiated prices.¹⁹ In its place, the province implemented a monitoring system comparing monthly domestic prices to export prices and the price of gas sold to Canadian customers outside the province. The province also instituted a complaint procedure that permits the denial of an export application where it is shown that British Columbia utilities and direct purchasers are unable to contract for gas on terms and conditions similar to those of proposed exports.

In addition, the province eliminated its mandatory surplus test which prevented the removal of natural gas from the province unless it was shown to be surplus to provincial current and forecast demand requirements. Under the province's former policy, long-term energy removal applications had to be supported by established reserves.²⁰ It replaced the test with a process of evaluation, audit, and monitoring of committed and available lands and reserves, production and deliverability from connected reserves and the markets to which reserves are dedicated. The new policy implements a flexible reserve dedication with a minimum reserve requirement of fifty to one hundred percent of the applied for volume to be supported by "established reserves" at the time of application. The application must also be supported by a prudent program for establishing the balance of the reserves. The province has continued its current practice of permitting short-term exports of less than two years duration without reserves dedication.

The maximum term for a long-term removal permit will be fifteen years unless the Ministry is persuaded that a longer term is required to make the sales transaction or pipeline project financially viable. If contract terms greater than fifteen years are approved for the domestic market, the Ministry will consider approving the same term for the export market.

19. Ministry of Energy, Mines and Petroleum Resources, Energy Resources Div., "British Columbia Natural Gas Removal Policy. A Policy Paper", May 1990, page 7. The abolition was effective October 31, 1990.

20. Surplus was defined as established reserves less fifteen times core market requirements less non-core market firm requirements less remaining firm export commitments. Core Market was defined as residential, commercial, institutional and small industrial consumers who have no alternative fuel burning capability and who are not direct purchasers. Established reserves are defined as proven reserves plus probable reserves discounted for risk.

B. National Energy Board of Canada

1. Benefit/Cost Test

As discussed in the 1989 committee report, the NEB reviewed the continued appropriateness of its benefit/cost test for export applications. This followed strong criticism that the test violated the Canada/U.S. Free Trade agreement.

The test was used by the Board in its market-based procedure as part of its public interest determination for export licenses. The test requires that a proposed export must recover all incremental costs incurred including production, gathering, and transportation as well as social costs. Social costs include the increased cost of developing new gas reserves to meet existing domestic and export needs.

On March 15, 1990, the NEB announced that it would discontinue use of the benefit/cost analysis of applications for export licenses because the test had become unreliable as a gauge of public interest.²¹ The Board noted that, because of the wide fluctuations in the test results depending on the assumptions and forecasts used, the test was of questionable value and agreed to review ten export applications rejected or modified within the prior year due to the application of the benefit/cost test or insufficient contractual flexibility. In cases where inadequate gas supply had been given as a reason for denial of a license, the Board advised that it would review its decision if it received evidence of a material change in the supply situation. On review, the NEB issued four of the previously denied licenses.²²

The Board will continue to examine contracts underlying gas export applications to assure itself that they have commercial substance and are durable over their term. Recognizing that contracts may be attractive notwithstanding a lack of flexibility, it indicated that it will generally presume that, when freely negotiated at arm's length, contracts are in the public as well as the private interest. The Board stated that it will intervene only in exceptional circumstances.

2. Export Impact Assessment

The NEB reviewed and amended its Export Impact Assessment (EIA) filing requirements. Applicants had previously been required to submit a detailed assessment of a proposal's impact on Canadian markets to assist the Board in determining whether the export was likely to cause difficulty in meeting Canadian energy requirements at fair prices. There were two major problems with the requirement: first, the difficulty of measuring the impact of small export projects, and second, uncertainty on the part of applicants as to how to satisfy the requirements.

Rather than abandon the analysis entirely, the Board will no longer require applicants to file the assessment as part of the application but will prepare its own study in consultation with the industry and interested parties.

21. National Energy Bd., No. GHW-4-89 (March 15, 1990).

22. National Energy Bd., No. GH-1-90 (June 1990).

The Board's reason for retaining the assessment was its concern that, while flexible prices in a competitive industry may be expected to provide a balance of supply and demand over time, market failure could nevertheless occur. An EIA, by identifying potential market adjustment problems, assists the Board in fulfilling its statutory requirement that it determine whether exports will remove gas required to meet the reasonably foreseeable demand for gas in Canada.²³

The NEB's study will cover long-term supply, demand prices, and export levels on a generic basis, addressing only the effect that various export levels will have on Canadian supply, demand, and prices. Applicants and intervenors may use the Board's analysis or prepare their own. If no problem is identified, the Board will presume that the proposed export will not cause difficulty in meeting Canadian energy requirements at fair market prices.

3. TransCanada Pipelines' 1991/1992 Facilities Application

In *TransCanada Pipelines*, the NEB considered TCPL's application for a \$2.6 billion (CDN) expansion of its facilities to increase deliveries to its domestic markets in Eastern Canada and to export markets in the U.S. Northeast.²⁴ The proposed facilities consist of 1,592 km of new pipeline designed to carry an additional 105.5 MMcfd for domestic markets and 726 MMcfd for export markets. The major issue in the proceedings was the rate treatment for the new facilities.

Under TCPL's current toll system, new facilities' costs are rolled into its cost of service and spread evenly among all of its customers, existing or new, without regard to whether the facilities are needed to serve export or domestic markets. Under this method the capital and operating costs of new facilities are added to those of the existing facilities and the total costs are then allocated on a volume-distance basis. TCPL calculated that the addition of the proposed facilities would result in an increase in the Eastern Zone firm service toll of approximately \$0.10/GJ.

The Industrial Gas Users Association (IGUA) and others were concerned that this would result in Eastern Canadian customers subsidizing, in their view, a new pipeline system to serve a new, regionally distinct U.S. export market. The NEB, although finding the issue relevant, rejected the IGUA's requests to include tolling methodology as an issue in the proceedings on the grounds that it had fully examined the appropriate toll methodology applicable to the then current and future TCPL expansions in prior proceedings.

The IGUA joined the Ontario Government and Consumer Gas Company in appealing the Board's refusal to the Federal Court of Canada. The appellants argued that the Board's decision not to include the tolling methodology in the list of issues for hearing, after conceding its relevance, was contrary to its statutory obligations under the National Energy Board Act. The Federal

23. National Energy Board Act Section 118, ch.7, 1990 Can. Stat. 118.

24. TransCanada Pipelines Ltd., Nat'l Energy Bd., No. GH-5-89, Reasons for Decision (Nov. 1990).

Court granted the motions and directed the Board to consider the issue.²⁵

A number of variations from rolled-in treatment were advanced. The IGUA proposed that the cost of all new facilities required to serve the U.S. Northeast should be included in a separate rate base, with costs assigned to each rate base according to the ratio of shipper volume-distance units for each market. Because actual operations of the existing and new facilities will be integrated, all system operating and maintenance costs would be shared by all customers on a volume-distance basis.

The Canadian Petroleum Association (CPA) proposed a variation from rolled-in treatment under which one-half of the additional capital burden attributable to the expansion would be rolled-in, with the balance of the capital burden recovered from the new shippers as a direct payment capital contribution. Similarly, Consumers' Gas Company Limited proposed rolled-in tolls but with a demand surcharge payable by new shippers. Union Gas Limited supported rolled-in tolls modified to reduce the risk of underutilization of the new facilities by setting the rolls based on a forecast of export volumes to the U.S. Northeast market with no revenue deferral account to cover any variances between forecasted and actual volumes.

The NEB, however, was not persuaded by these proposals and ordered all facilities rolled into TCPL's rate base for toll purposes.²⁶ It rejected arguments that the size, cost, or impact of the expansion warranted a different rate treatment, noting that in real terms, even with the impact of new facilities included, the toll in 1995 would be lower than it was two years ago. The Board concluded that the primary effect of the alternative tolling methodologies proposed by the parties was to shield existing shippers from additional costs associated with new facilities and reiterated its view that the payment of tolls confers no future benefits on tollpayers beyond the provision of service. Since existing shippers acquire no rights in the system, they should not be exempted from a toll increase simply because they paid tolls in the past.

The Board also rejected the notion that the U.S. Northeast is a new, regionally distinct market, as Canadian gas has been flowing to that market since 1984. Nor could the expansion be considered a new pipeline since it is physically integrated with the existing system. The Board was persuaded that the aggregate demand of all shippers gave rise to the need for the additional pipeline capacity.

Finally, although agreeing that there is some theoretical support for the idea that incremental tolls achieve economic efficiency results superior to rolled-in tolls, due to the lack of empirical evidence submitted, the Board was not persuaded that the implementation of any of the proposed incremental toll methodologies would yield significant economic efficiency improvements over

25. *Industrial Gas Users Ass'n v. NEB*, Federal Court of Canada, No. T-29984-89, Reasons for Decision, (February 14, 1990). The IGUA subsequently argued that the Federal Court order required the Board to consider toll methodology not only with regard to the proposed facilities but with respect to traffic on previously certificated facilities as well. The Federal Court denied the request on a decision delivered on August 17, 1990.

26. *TransCanada Pipelines Ltd., Nat'l Energy Bd.*, No. GH-5-89, Reasons for Decision (Nov. 190), p. 13.

the rolled-in tolling methodology. It did, however, maintain a mileage based methodology for determining export tolls rather than adopt suggestions that export tolls be rolled into the Eastern Zone postage stamp toll applicable to domestic customers.

The Board's facilities hearing also focused on the economic feasibility of the proposed expansion. It traditionally looks at evidence indicating that the facilities will be used and useful over their economic life, including evidence on the existence of a long-term market to be served, the adequacy of long term gas supplies, and the commitments of contracting parties to pay the necessary demand charges. A number of parties argued that under the rolled-in methodology, shippers may pay a toll which fails to reflect the real incremental cost of service and supported adoption of a specific, quantitative economic feasibility test. The Alberta Energy Commission recommended adoption of a market-based procedure to compare contract netbacks with the requirement that only contracts with a minimum ten-year term be used to justify an expansion. The Alberta Petroleum Marketing Commission, the Independent Petroleum Association of Canada, and ProGas proposed discounted cash flow analysis techniques to estimate whether new gas sales would be economically viable from the overall viewpoint of the gas producing sector. Union Gas proposed a three-stage approach that combines discounted cash flow analysis with identification and analysis of non-quantifiable benefits or costs such as security of supply and environmental impacts. Other parties, including the CPA, Consumers', and the IGUA argued that a form of incremental tolling could provide an appropriate test of the economic feasibility. Other parties making arguments were the Alberta Northeast Export Project and Canadian Hunter.

The Board rejected all the proposed economic feasibility tests as well as incremental tolls, noting its general concerns with the tests proposed: the lack of consensus on the fundamental variables to be applied; the questionable usefulness of tests that are non-determinative; the lack of a direct relationship between certificated capacity and those volumes that have access to the pipeline; and the fact that the proposed tests would apply only to incremental volumes or renewals and not to all flowing volumes.

The Board concluded that the economic feasibility determination is most appropriately made through an assessment of whether the facilities will be used at a reasonable level over their economic life and the demand charges paid. In making this assessment, it will consider: the sufficiency of long-term supply; the long-term outlook for gas demand in the market to be served; the potential of competing supplies, energy sources, and transportation systems; the underlying contracts including evidence that the demand charges will be paid; the adequacy of supply, upstream and downstream transportation arrangements, regulatory approvals in place prior to construction, and the financial integrity of the parties; the risks associated with new gas sales, including regulatory risks in other jurisdictions; and the likelihood of a toll increase caused by the expansion resulting in reduced demand for firm service. The onus is on TCPL to demonstrate that the facilities will be sufficiently well-utilized and to submit evidence on all factors relevant to the determination.

III. DEVELOPMENTS IN THE UNITED STATES—MARKETERS

On January 31, 1990, in response to applications from several marketers to clarify or amend existing blanket sales certificates, the Commission asserted jurisdiction over imported gas sold by marketers for resale in interstate commerce.²⁷ The Commission found amendment of the certificates necessary because the existing authorizations applied only to gas subject to Title I of the Natural Gas Policy Act (NGPA) that had not been removed from the Commission's Natural Gas Act (NGA) jurisdiction by section 601 of the NGPA.²⁸

In amending the blanket certificates, the Commission further found that, in the absence of new facilities construction in connection with the sale of the imported gas, no purpose would be served by imposing a "cap" on the price that marketers can charge. The Commission reasoned that market forces would keep the rates charged by these marketers in line with those charged by American producers.²⁹ The Commission also held that pipelines purchasing imported gas would remain subject to previous Commission orders concerning pipeline pricing of such gas.³⁰ The Commission pointed out that pipeline purchasers would be subject to prudence review as a further check on the level of rates paid for imported gas, and that local public utility commissions would maintain their ability to review purchases of imported gas from these marketers made by local distribution companies within their jurisdictions.³¹

On May 4, 1990, the Commission issued an order clarifying, and denying rehearing of, its January order.³² It rejected contentions that it lacked jurisdiction over sales for resale of imported natural gas, reiterating that NGPA Title I restraints on jurisdiction did not apply to resales of imported gas. Noting that the NGPA's price ceilings applied only to "first sales" of natural gas produced in the United States, the Commission stated:

Since first sales were defined in the NGPA for the purpose of establishing those transactions to which ceiling prices would apply, and since ceiling prices apply only to domestic production, it is reasonable to conclude that the term, "first sale" does not include sales of imported gas. Thus, sales of imported gas are not, as we indicated in *Salmon*, deregulated by section 601(a)(1)(A) and marketers seeking to sell imported gas for resale in interstate commerce require a certificate.³³

The Commission also disagreed with contentions that the exercise of jurisdic-

27. *Salmon Resources Ltd.*, 50 F.E.R.C. ¶ 61,101, at 61,325 (1990). *Salmon Resources* sought, if the Commission found it had jurisdiction, amendment of *Salmon Resources'* blanket certificate to include authorization for the sale for resale on the spot market of gas imported from Canada. *Enron Gas Marketing, Inc.* sought authorization of the sale for resale of Canadian gas it had purchased from *Natgas (U.S.), Inc.*, and *V.H.C. Gas Systems, L.P.* sought authorization of the sale for resale of liquefied natural gas imported from Algeria.

28. 50 F.E.R.C. ¶ 61,101 at 61,328. As the Commission explained, *supra* note 17, section 101(b)(4)(A) of the NGPA, 15 U.S.C. § 3311(b)(4)(A) (1988), only applies to gas produced in the United States.

29. *Id.*

30. *Id.* See *Natural Gas Pipeline Co. of America*, 37 F.E.R.C. ¶ 61,215 (1986), *order on reh'g*, 39 F.E.R.C. ¶ 61,218 (1987), *aff'd sub nom.*, *TransCanada Pipelines Ltd. v. FERC*, 878 F.2d 401 (1989).

31. 50 F.E.R.C. ¶ 61,101, at 61,328.

32. *Salmon Resources Ltd.*, 51 F.E.R.C. ¶ 61,148, at 61,398 (1990).

33. 51 F.E.R.C. ¶ 61,148 at 61,399.

tion over the sale for resale of imported gas was redundant given the jurisdictional responsibilities of the Department of Energy's Office of Fossil Energy. Noting that it was "obligated" to exercise jurisdiction over such sales, the Commission pointed out that whereas the DOE/FE authorizes the importation of natural gas, the Commission has jurisdiction over that gas whenever it involved the sale for resale or transportation in interstate commerce.³⁴

The Commission also dismissed arguments that its exercise of NGA jurisdiction over imported gas was contrary to pro-competitive policy goals, pointing to Order Nos. 436 and 500 as recent examples of "regulation which reflect[s] the Commission's preference for competition in the marketplace[.]" and stating that their decision not to impose rate controls on the sale for resale of imported gas was another such "example of regulatory restraint designed to promote competition."³⁵ The Commission went on to reject suggestions that Salmon's sales authorizations be limited to markets served by open-access pipelines, asserting that such a requirement would be "unnecessary and discriminatory."³⁶

Tenngasco Exchange Corporation, one of the parties that sought rehearing of the Commission's January order, filed a petition for review of both orders in the District of Columbia Circuit on July 3, 1990. On August 14, 1990, the Commission filed a motion to dismiss this petition for lack of aggrievement. To date, the court has taken no action on either the petition or the Commission's motion. The Commission has continued to assert its jurisdiction over sales for resale of imported gas.³⁷

IV. ELECTRICITY

On October 12, 1990, the Vermont Public Service Board (VPSB) approved a thirty-year firm power purchase contract between Hydro-Quebec and all twenty-four of the state's electric utilities. The VPSB determined that the contract provided an economical, reliable, and environmentally attractive supply source. As approved, the power contract was subject to conditions including the requirements that the utilities: (1) pursue cost-effective energy-efficiency programs; (2) allocate contract power in the best interests of each utility and the state; and (3) negotiate with Hydro-Quebec for return sales of surplus power. The VPSB also approved a minimum purchase requirement contained in the contract. Another major component, options for additional purchases, was eliminated, in part because of a lack of evidence that cumulative environmental impacts in Quebec would not affect Vermont's environment adversely.³⁸

34. *Id.*

35. *Id.*

36. 51 F.E.R.C. ¶ 61,148, at 61,400.

37. See e.g. *Ocean State Power*, 53 F.E.R.C. ¶ 61,389 (1990) (granting blanket authority with pre-granted abandonment to Rhode Island cogeneration facility to sell surplus Canadian gas).

38. Vermont Public Service Board, Docket No. 5330 (October 12, 1990).

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