Cited as "1 FE Para. 70,502"

New England Power Company (FE Docket No. 90-09-NG), November 27, 1991.

DOE/FE Opinion and Order No. 551

Order Granting Long-Term Authorization to Import Natural Gas from Canada and Granting Intervention

I. Background

On February 9, 1990, New England Power Company (NEP), filed an application with the Office of Fossil Energy of the Department of Energy (DOE) under section 3 of the Natural Gas Act (NGA) and DOE Delegation Order Nos. 0204-111 and 0204-127 for authorization to import natural gas from Canada. NEP proposes to import on a firm basis up to 60,000 Mcf per day of gas over a period of 15 years beginning the later of November 1, 1991, or the date the authorization is issued.

The applicant, a Massachusetts corporation with its headquarters in Westborough, Massachusetts, is engaged in the generation and transmission of electric power for sale at wholesale to affiliated and unaffiliated utilities in the New England region. The imported gas would be used to generate electricity and, in particular, would displace residual fuel oil currently being burned at NEP's Brayton Point electric generating station in Somerset, Massachusetts, and would fuel its Manchester Street Station in Providence, Rhode Island. The gas may also be used to fuel the South Street Station, also located in Providence, Rhode Island.

NEP is overhauling its four-unit Brayton Point Station to reduce the sulfur dioxide emissions. Brayton Point Unit No. 4, a 430-megawatt (MW) oil-fired unit, would be modified to add natural gas burning capability. When Unit No. 4 is transformed to a dual-fired station and starts running on gas, it is expected to consume about 95,000 Mcf of gas per day.

NEP also intends to repower the Manchester Street facility to convert the unit to a combined-cycle station fired by firm gas supplies, with the ability to use No. 2 oil as an emergency backup. This power plant currently relies on residual oil, using interruptible supplies of gas when available. The installation of gas-fired combustion turbines and heat recovery steam generators at the Manchester Street Station would increase its output from 150 MW to 450 MW. This project would burn from 75,000 to 80,000 Mcf of gas on an average daily basis and is not expected to be in service before November 1994.

NEP has certified to DOE, pursuant to the Powerplant and Industrial Fuel Use Act of 1978 (FUA), as amended,1/ that the added new equipment at the Manchester Street plant would be capable of using coal or another alternate fuel as a primary energy source.2/ Brayton Point Unit No. 4 was designed as a residual oil burning unit and has never been coal-capable. It is not subject to the FUA.

The 60,000 Mcf per day of Canadian gas that NEP proposes to import and receive at the power plants would be purchased in Canada from four producers: BP Resources Canada Limited (BP Canada) (10,000 Mcf/d), Renaissance Energy Limited (Renaissance) (15,000 Mcf/d), Sceptre Resources Limited (Sceptre) (20,000 Mcf/d), and Triton Canada Resources Limited (Triton) (15,000 Mcf/d). The gas would be imported at the U.S./Canada border near Iroquois, Ontario and

Waddington, New York through a new pipeline interconnection between Iroquois Gas Transmission System (Iroquois) and TransCanada PipeLines Limited, with further downstream transportation to the generator plants by Tennessee Gas Pipeline Company (Tennessee) and Algonquin Gas Transmission Company (Algonquin).

NEP's contracts with BP Canada, Sceptre, and Triton have 20-year terms; the Renaissance contract extends for a primary term of 15 years with an optional five-year extension. The contract prices that NEP would pay for the gas are set in the field, except in the Renaissance contract, where the price is determined at Empress, Alberta. Generally, all pipeline transportation costs would be billed directly to NEP. In the Renaissance contract, however, NEP would compensate Renaissance for the cost to transport the gas to the Alberta/Saskatchewan border near Empress by paying a higher base price.

The prices under the four contracts are adjusted in accordance with pricing mechanisms directly tied to fossil fuel indices. Although natural gas is the primary component of the index in every case, some contain oil or coal components, and all are designed to allow the price of the gas to track monthly changes in NEP's total fossil fuel supply costs. NEP expects that the indices will yield contract prices that reflect the market price of natural gas. However, if a significant divergence emerges, the parties may elect to renegotiate the prices. Each of the four contracts contains a provision that permits reopening of the price every two years. If price redetermination is not agreed upon within three months of the initial request for it, then either party may terminate the contract.

NEP estimates that if the gas supplies had been flowing on October 1, 1991, the total delivered cost of the imports at the international border would have been $2.40 /MMBtu (BP Canada), $2.50 /MMBtu (Renaissance), $2.27 /MMBtu (Sceptre), and $2.25 /MMBtu (Triton).3/ This equates to a weighted average import price of $2.35 /MMBtu at a 100 percent load factor.

The contractual provisions unique to each of the contracts are summarized below.

A. BP Canada

The initial base price is $1.33 per MMBtu, adjusted monthly by an index comprised of: (1) Tennessee's cost of gas in Louisiana and offshore, (2) ANR Pipeline Company's cost of gas in Oklahoma, and (3) the average cost of oil purchased by New England Power for its power plants. The contract price may be redetermined beginning November 1, 1992 and every second year thereafter under the following circumstances. NEP may request redetermination of the contract price if, over any four consecutive months during the preceding two years, the price does not allow NEP's gas-fired plants to operate at an average 90 percent net capability. BP may request redetermination of the contract price if, over any consecutive four-month period, it averaged less than 90 percent of the Average Alberta Market Price (AAMP) 4/ during the same period. The contract has an 80 percent minimum annual take provision. If NEP fails to take the minimum amount of gas, BP Canada can charge a reservation fee or reduce the daily contract quantity.

B. Renaissance

The initial base price is $1.37 per MMBtu, adjusted monthly by an index comprised of: (1) Tennessee's weighted average cost of gas (WACOG), (2) Texas

Eastern Transmission Corporation's WACOG, and (3) NEP's average cost of oil and coal reported in its Federal Energy Regulatory Commission (FERC) Form 423 for such month. Redetermination of the contract price is permitted after the second contract year and every two years following the last redetermination. There is an 80 percent minimum annual take provision. The amount of gas that Renaissance is obligated to supply (MDQ) is subject to reduction if NEP fails to take the minimum volumes. If deficiencies occur in any two consecutive contract years and the MDQ in the second year has been reduced, Renaissance would have the right to terminate the contract.

C. Sceptre

The price each month is the sum of: (1) one-half the AAMP for such month, (2) one-half of the difference between NEP's weighted average reported fossil fuel commodity costs for such month, and (3) a variable amount expressed in dollars per MMBtu (the "Dispatch Factor") based on NEP's expenses of operating its power plants. The contract price may be redetermined beginning November 1, 1992, and every second year thereafter. Redetermination of the contract price is permitted if, for any consecutive six-month period, NEP's gas-fired plants could not operate at an average 80 percent net capability or the average contract was less than 90 percent of the AAMP. There is a 65 percent minimum annual take provision. If the minimum amount of gas is not taken, NEP may pay a reservation fee or allow Sceptre to reduce the daily contract quantity.

D. Triton

The price each month is the sum of: (1) 85 percent of the AAMP and (2) an amount equal to 50 percent of the levy imposed on the gas by the Alberta Petroleum Marketing Commission pursuant to the Take-or-Pay Cost Sharing Act of Alberta. The contract price may be redetermined after November 1, 1993, and every two years following the last redetermination. NEP may request redetermination if the price does not allow NEP's power plants to operate at an average 80 percent net capability during any year. Triton may request redetermination if the contract price during any year was less than 85 percent of the price of Alberta gas sold for electric generation into New England. There is a 65 percent minimum annual take provision. If the minimum amount of gas is not taken, NEP may pay a reservation fee or allow Triton to reduce the daily contract quantity.

In support of its application, NEP asserts that additional firm gas supplies as an alternative to oil would enhance the security and reliability of the New England region's fuel supply. Currently, the region's electric utilities are highly dependent on imported oil. In addition, adding gas burning capability to the Brayton Point facility would help achieve compliance with the Massachusetts Acid Rain Law that was enacted to improve air quality by requiring sizable reductions in sulphur dioxide emissions. Moreover, the natural gas repowering of the Manchester Street Station would add generation capacity to meet growing electricity demand in New England.

DOE published a notice of receipt of NEP's application in the Federal Register on April 20, 1990,5/ inviting protests, motions to intervene, notices of intervention, and comments to be filed by May 21, 1990. A motion to intervene without comment or request for additional procedures was filed by Boston Gas Company. This order grants intervention to Boston Gas Company.

II. Decision

The application filed by NEP has been evaluated to determine if the proposed import arrangement meets the public interest requirements of section 3 of the NGA. Under section 3, an import must be authorized unless there is a finding that it "will not be consistent with the public interest." 6/ This determination is guided by DOE's natural gas import policy guidelines, under which the competitiveness of the import in the markets served is the primary consideration for meeting the public interest test.7/ DOE also considers, particularly in long-term arrangements, need for and security of the imported gas supply. In addition, the environmental effects of natural gas import arrangements are considered.

A. General Policy Considerations

The DOE guidelines state that the competitiveness of an import arrangement will be assessed by a consideration of the whole fabric of the arrangement. They contemplate that the contract should be sufficiently flexible to permit pricing and volume adjustments as required by market conditions and availability of competing alternative fuels, including domestic natural gas.

NEP's uncontested import proposal, as a whole, is competitive. The prices specified in the four contracts are tied to natural gas prices and/or are linked to other fossil fuel indices in the pricing mechanism. The indices are designed to allow the price of the gas to partially track monthly changes in NEP's total fossil fuel supply costs so that NEP's electric generating units will continue to operate at high load factors. All four contracts contain provisions permitting reopening of the price every two years. NEP noted that these reopeners will likely result in prices being paid under these contracts which, over the life of the contracts, will track the market price for gas. Finally, the contracts contain no take-or-pay provisions, but permit the suppliers to reduce the contract volumes if NEP's nominations are less than the minimum annual quantity. Under these conditions, NEP is not obligated to import volumes unneeded by its generation stations.

B. Environmental Aspects

1. Overview

Environmental concerns are an important element in DOE's public interest determination. In general, DOE considers environmental issues in the context of the National Environmental Policy Act (NEPA) of 1969.8/ This import is part of the second phase of the Iroquois/Tennessee Pipeline Project, a proposal to construct and operate pipeline facilities, including the new 365-mile Iroquois system extending from the U.S./Canada border through eastern New York and western Connecticut and terminating on Long Island, New York. The entire project (Phase I and II), as proposed, would transport up to 575,900 Mcf per day of natural gas (primarily Canadian) on a firm basis to 17 local distribution companies, three cogeneration customers, and one electric generation customer in the northeastern United States. Iroquois would deliver part of the gas directly to certain customers and deliver the remaining volumes to Tennessee, Algonquin, and Texas Eastern Transmission Company for redelivery to the remaining Iroquois customers.

To build the facilities used to transport Canadian gas as the Iroquois/Tennessee Project sponsors propose, there must be approval from FERC. Under section 3 of the NGA, FERC has jurisdiction over the siting, construction, and maintenance of pipeline facilities that cross the international border from Canada and enter the United States. In addition, under section 7 of the NGA, FERC is responsible for determining that interstate natural gas transportation facilities are in the public interest. If FERC determines that the border-crossing facilities would not be inconsistent with the public interest and there is or will be a need for a proposed service, it will issue a Presidential Permit and a Certificate of Public Convenience and Necessity authorizing the construction and operation of a proposed project.

As the lead Federal agency for the Iroquois/Tennessee Project, FERC was responsible for developing information and preparing the relevant documents to identify the potential environmental impacts from the project in compliance with NEPA and the Council on Environmental Quality regulations for implementing NEPA (40 CFR Parts 1500-1508). FERC divided the Iroquois/Tennessee Project into two phases by an order issued July 30, 1990.9/ Phase I involved construction and operation of virtually all of the Iroquois pipeline system (except an interconnection with Algonquin) to provide transportation for up to 422,900 Mcf per day of gas. That phase also involved construction of 63 miles of pipeline facilities by Tennessee. Phase II involves the construction of pipeline, compression, and metering facilities by Iroquois, Tennessee, and Algonquin that would be used to transport and deliver up to 153,000 Mcf per day of Canadian gas for NEP and five other importers.

On November 14, 1990, FERC issued a Presidential Permit to Iroquois and certificated the Phase I facilities.10/ DOE issued final authorization for importation of the Phase I volumes on November 15, 1990.11/ The potential environmental effects of the Phase I facilities were addressed in a final Environmental Impact Statement (EIS) issued by FERC on June 1, 1990 (which was adopted as DOE/EIS-0152). They were also discussed in DOE's Record of Decision for granting the Canadian gas import applications related to Phase I.12/ DOE concluded that the anticipated overall physical impacts of the proposed Phase I facilities on the natural environment would be relatively minor and could be mitigated. Construction of the Iroquois mainline is nearly completed and it will soon be placed in operation.

In September 1991, FERC issued an Environmental Assessment (EA) for Phase II (which was adopted as DOE/EA-0592). The Phase II facilities consist of 25.4 miles of pipeline loop, 21.3 miles of replacement pipeline, 3.6 miles of new lateral, 19,500 horsepower of compression (including two new compressor stations), and various metering facilities to be constructed in Connecticut, Massachusetts, Rhode Island, and New York. On October 9, 1991, Phase II was certificated by FERC.13/ The FERC certificate imposed environmental conditions outlined in the EA to minimize the impact associated with construction and operation of the proposed facilities. In addition, it prohibited construction of any Phase II facilities until Iroquois, Tennessee, and Algonquin file with FERC copies of final DOE import authorizations for all Canadian gas that would be delivered in Phase II.

2. Impacts

The EA for Phase II of the Iroquois/Tennessee Project addresses construction procedures for the proposed pipelines and aboveground facilities; erosion control and revegetation plans for the construction rights-of-way; impact on streams and wetlands, vegetation, wildlife, fisheries, threatened or endangered species, noise and air quality, land use, public lands (including the Appalachian National Scenic Trail), state forests and state wildlife management areas, residential areas, and cultural resources; polychlorinated biphenyls; and alternatives to the proposed pipeline routes and new aboveground facility sites. In addition, the document recommended that FERC include 24 environmental mitigation measures in any certificate issued to Tennessee and Algonquin. The EA concluded that if constructed in accordance with the recommended mitigation measures, the proposed Iroquois/Tennessee Phase II Project would not be a major Federal action significantly affecting the quality of the human environment within the meaning of NEPA, and would therefore not require the preparation of an EIS.

Inasmuch as the information and analysis in the EA determined that construction of the facilities for Phase II of the Iroquois/Tennessee Project would not result in significant long-term or cumulative environmental impacts, DOE believes that NEP's import proposal does not constitute a major Federal action significantly affecting the quality of the human environment within the meaning of NEPA. Therefore, no environmental impact statement is required and DOE issued a finding of no significant impact (FONSI) on November 26, 1991.14/

III. Conclusion

After considering all of the information in the record of this proceeding, I find that granting NEP authorization to import up to 60,000 Mcf per day of natural gas from Canada over a period of 15 years beginning on the date of this order, in accordance with the provisions of its gas purchase agreements with BP Canada, Renaissance, Sceptre, and Triton, is not inconsistent with the public interest.15/

ORDER

For the reasons set forth above, pursuant to section 3 of the Natural Gas Act, it is ordered that:

A. New England Power Company (NEP) is authorized to import up to 60,000 Mcf per day of natural gas from Canada at a point on the international border near Iroquois, Ontario/Waddington, New York, effective on the date hereof and continuing for a period of 15 years.

B. The importation of natural gas hereby authorized shall be accomplished in accordance with the provisions of NEP's supply contracts with BP Resources Canada Limited, Renaissance Energy Limited, Sceptre Resources Limited, and Triton Canada Resources Limited which were described in the application filed in this proceeding and are discussed in this Opinion and Order.

C. NEP shall notify the Office of Fuels Programs (OFP), Fossil Energy, FE-50, Forrestal Building, 1000 Independence Avenue S.W., Washington, D.C. 20585, in writing of the date of initial deliveries of natural gas imported under paragraph A above within two weeks after deliveries begin.

D. With respect to the imports authorized in paragraph A above, NEP shall file with OFP, within 30 days following each calendar quarter, quarterly reports showing by month, the total volume of natural gas imports in Mcf under each of NEP's supply contracts, the average purchase price per MMBtu at the U.S./Canada border under each of the contracts, and a weighted average of the prices. If no imports have been made, a report of "no activity" for that calendar quarter must be filed. The price information for a particular month shall list separately (on a per unit (MMBtu) basis) the commodity charge, the transportation charges associated with the sale to the U.S./Canada border, and any reservation fee NEP may have paid for minimum take deficiencies.

E. NEP shall notify OFP in writing within two weeks of the effective date of any reduction in the "Maximum Daily Quantity" under the NEP gas purchase contracts with its four suppliers.

F. The first quarterly report required by paragraph D above is due not later than January 30, 1992, and should cover the period from the date hereof until the end of the current calendar quarter, December 31, 1991. Failure to file quarterly reports may result in termination of the authorization.

G. The motion to intervene filed by Boston Gas Company is hereby granted, provided that its participation shall be limited to matters specifically set forth in its motion to intervene and not herein specifically denied, and that admission of this intervenor shall not be construed as recognition that it may be aggrieved because of any order issued in this proceeding.

Issued in Washington, D.C., November 27, 1991.

--Footnotes--

1/ 54 F.R. 52886, December 22, 1989.

2/ 55 F.R. 11053, March 26, 1990.

3/ See letter from Mr. Mitchell F. Hertz filed November 15, 1991, on behalf of NEP.

4/ Published by the Government of Alberta.

5/ 55 F.R. 14999 (April 20, 1990).

6/ 15 U.S.C. 717b.

7/ 49 F.R. 6684, February 22, 1984.

8/ 42 U.S.C. 4321, et seq.

9/ Iroquois Gas Transmission System, L.P., 52 FERC Para. 61,091.

10/ Opinion No. 357, 53 FERC Para. 61,194; Opinion No. 357-A, rehearing denied in part and granted in part, 54 FERC Para. 61,103 (February 4, 1991).

11/ See Brooklyn Union Gas Company, et al., 1 FE Para. 70,370 (November 15, 1990), rehearing denied, 1 FE Para. 70,400 (January 16, 1991); Orchard Gas Corporation, 1 FE Para. 70,374 (November 15, 1990); Selkirk Cogen Partners, L.P., 1 FE Para. 70,375 (November 15, 1990); Pawtucket Power Associates, 1 FE Para. 70,376 (November 15, 1990); and Granite State Gas Transmission, Inc., 1 FE Para. 70,377 (November 15, 1990).

12/ See 55 F.R. 48685, November 21, 1990.

13/ See Iroquois Gas Transmission System, L.P., et al., 57 FERC Para. 61,047.

14/ The FONSI is available in the Office of Fuels Programs public file associated with this proceeding.

15/ In conjunction with this order, DOE is issuing final authorization to Connecticut Natural Gas Company and New York State Electric and Gas Corporation (ERA Docket Nos. 86-44-NG, et al.); Yankee Gas Services Company (FE Docket No. 91-11-NG); Boston Gas Company (FE Docket No. 89-38-NG); and Granite State Gas Transmission, Inc. (FE Docket No. 90-23-NG) for importation of the remaining 93,000 Mcf per day of the 153,000 Mcf per day Phase II volumes.