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# Toward the Integration of Canadian and United States Natural Gas Import Policies

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# TOWARD THE INTEGRATION OF CANADIAN AND UNITED STATES NATURAL GAS IMPORT POLICIES

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*As the United States and Canada move to deregulate the natural gas market, economic forces will begin to determine supply and demand levels of natural gas. In a two-part article, the author discusses the two countries' efforts to integrate their natural gas import policies. The first part, printed here, deals with the background of the United States and Canadian natural gas policies, the countries' differing perspectives on the natural gas market, and the legal and institutional environment in the United States. The second part, to be published in the Spring issue, will deal with the legal and institutional environment in Canada, the U.S.-Canada Free Trade Agreement, and issues for the future of the cross-national natural gas market.*

## I. INTRODUCTION

An understanding of the historical development of U.S. and Canadian natural gas markets and their governmental regulation is necessary in order to achieve a perspective on their contemporary interaction. Generally, the United States has looked to Canada to provide a supplemental portion of firm, base load supply to be delivered according to the terms of long-term contracts and export licenses.[1] More recently, Canadian natural gas has tended to serve as a swing source of supply, heavily exploited when demand is high and excluded from the U.S.

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1. P. Daigneault, Canadian Natural Gas Trade - It's Come a Long Way in a Relatively Short Period of Time, Conference on Marketing Canadian Gas in the United States, Executive Enterprises, Inc. (Feb. 7, 1985).

market through regulatory and other policy actions when domestic supplies are in surplus.[2]

A market-based approach to international trade regulation now complements domestic decontrol of the natural gas industry.[3] With the ratification of the Canada-U.S. Free Trade Agreement, independent initiatives for deregulation and decontrol can be coordinated through consultative procedures.[4]

The United States has been importing natural gas from Canada since the 1950s.[5] Unlike imports of natural gas from Mexico (strictly limited to domestic demand) and imports from other sources such as Algeria, Indonesia, and Norway (cost constrained by handling and transportation), Canadian natural gas is competitively priced and available in sufficient volume to satisfy demand.[6] Furthermore, Canadian natural gas is relatively easy to access through existing pipeline systems that interconnect with transportation and distribution networks in the northern Midwest, Pacific Northwest, and California. Additional expansions of the pipeline systems serving growing California and New England markets are under planning and certification.[7]

The delivery points of entry in the United States and the applicable Canadian counterparts are as follows:

1. Sumas, Washington/Huntington, British Columbia;
2. East Port, Idaho/Kingsgate, British Columbia;
3. Port of Del Bonita, Montana/Aden, Alberta;
4. Monchy, Saskatchewan;
5. Noyes, Minnesota/Emerson, Manitoba;
6. Ft. Frances, Ontario;

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2. OFFICE OF INTERNATIONAL ENERGY ANALYSIS, U.S. DEPT. OF ENERGY, U.S.-CANADA GAS TRADE REVIEW, 5 (Nov. 1987).

3. Buckley & Grammer, *Gas Trade With Canada: Breaking Down Barriers at the Border,* 2 NAT. GAS LAW J. 24-25 (1988).

4. T.D. McGee, Counselor (Energy) Canadian Embassy, Washington, D.C., Free Trade and Energy Price, Toronto, Ontario (Oct. 22, 1987). The Canada-United States Free-Trade Agreement was not limited to energy. It also dealt with the elimination of tariff and nontariff barriers, rules of origin, technical standards, wine and alcoholic beverages, trade in services, safeguards, investments, automotive trade, customs issues, agricultural commodities, government procurement and dispute settlement. *Id.*

5. New Policy Guidelines and Delegation Orders from Secretary of Energy to Economic Regulatory Administration and Federal Energy Regulatory Commission Relating to the Regulation of Imported Natural Gas, 49 Fed. Reg. 6684-6685 (1984). Initial imports from Canada in the 1950s were small, amounting to approximately 3 BCF per year. *Id.*

6. U.S.-CANADA GAS TRADE REVIEW, *supra* note 2, at 11-12.

7. *Greater Imports of Canadian Gas to the U.S. Are Stalled - Producers' Pipeline Expansion Proposals Caught in Regulatory Tangle,* Wall St. J., April 21, 1987, at 6, col. 1. Ten new pipeline projects with construction starting dates in 1987-1989 have been proposed for expanding Canadian natural gas import to the Northeast United States. *Id.*

7. Niagara Falls, New York;
8. Massena, New York/Cornwall, Ontario;
9. Highgate, Vermont/Philipsburg, Quebec.[8]

The delivery points of entry for Canadian natural gas into the continental United States are shown in Figure 1 according to level of use.

The pattern of use for Canadian natural gas is regionally stratified. Border states like Washington and New York are major markets as are states in the Great Lakes and Pacific coast.[9] With the advent of the spot market, imported natural gas is also being used as far away as Florida and in states with major domestic production like Texas and Louisiana.[10] However, in general, Canadian natural gas serves those markets that are closest to the source of supply.[11]

Canadian natural gas provides an alternative source of competition for domestic production (gas-to-gas competition) and is a secure, competitively priced alternative to imported oil. At a time when public awareness is focused on acid rain and other environmental issues associated with fossil fuel combustion, natural gas has a definite advantage over coal and high sulphur fuel oil.[12]

Therefore, while Canadian imports currently constitute between 3 and 5 percent of the total consumption of natural gas in the U.S., Canada is projected to remain the only significant source of imported natural gas up to the end of this century.[13] As domestic surpluses dissipate, volumes of natural gas imported from Canada are expected to increase and even double by the end of the century.[14]

In the last decade, several factors have exerted particular influence upon the gradual increase in cross-border trade in natural gas. During the period of U.S. natural gas shortages, Canadian imports reached the trillion cubic feet (TCF) level, but declined substantially in the 1980s in response to aggressive Canadian price increases.[15] During this period Canadian suppliers were accused of intentionally raising prices above clearing levels to take advantage of tight markets.[16] Additionally, a growing U.S. deliverability surplus was instrumental in the declining level of Canadian imports.[17]

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8. U.S.-CANADA GAS TRADE REVIEW, *supra* note 2, at 10.
9. CAMBRIDGE ENERGY RESEARCH ASSOCIATES, NATURAL GAS TRENDS, 1988-89 EDITION 71 (1988).
10. *Id.*
11. Interview with Andrea K. Waldham, International Energy Economist, Office of International Affairs, United States Dept. of Energy, in Washington, D.C. (Oct. 21, 1987).
12. NATURAL GAS TRENDS, *supra* note 9, at 1.
13. *Id.* at 3.
14. Interview with Andrea K. Waldman, *supra* note 11.
15. U.S.-CANADA GAS TRADE REVIEW, *supra* note 2, at 8-9.
16. Interview with Andrea K. Waldman, *supra* note 11.
17. U.S.-CANADA GAS TRADE REVIEW, *supra* note 2, at 8-9.

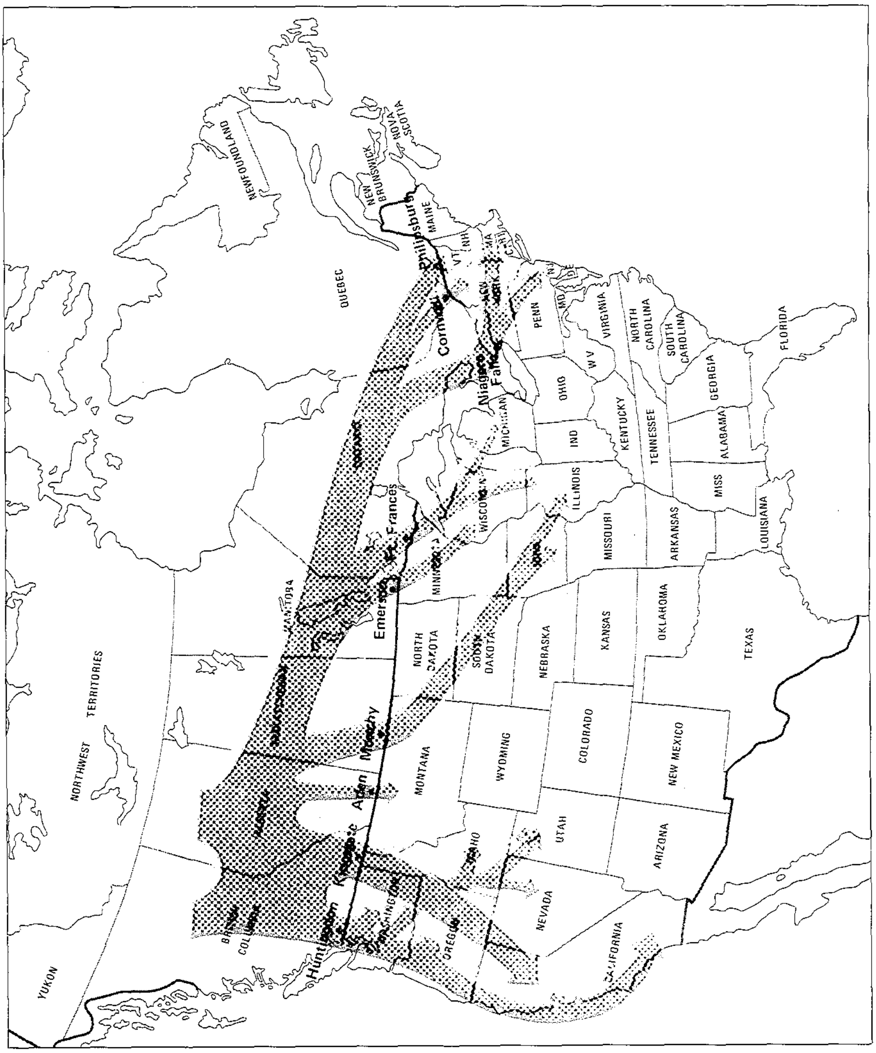


**Figure 1. Canadian Natural Gas Entry Points and Consumption Patterns.**

The goals of energy security, comprehensive deregulation, and bilateral free trade all played an important role in shaping U.S. policy toward trade in Canadian natural gas.[18] Natural gas easily substitutes for some liquid petroleum uses and is particularly valuable in reducing reliance on insecure sources of imported oil.[19] Consequently, imported natural gas is important to an overall strategy for energy security in the U.S.[20] With abundant resources located on the North American continent, natural gas is not subject to potential supply disruptions that can occur with fuels imported from less stable areas.[21]

Despite these attributes, Canadian natural gas does not stand on an equal footing in U.S. markets. For example, from 1985 to 1986 the decontrol of domestic wellhead prices for natural gas, coupled with increased reliance upon the spot market, and limited availability of open access to interstate pipelines, caused natural gas demand to decline by 7 percent.[22] During this period, Canadian imports declined by 19 percent due to lack of access to the spot market from limited availability of pipeline capacity.[23]

The history of regulation in the U.S. and Canada demonstrates the effect that the practices of each nation have had on natural gas trade between them. Past regulatory policies on both sides of the border served to distort the market by affecting prices and limiting levels of demand.[24] It is axiomatic in the regulatory process that decisions on a specific issue may have far-reaching and unintended economic consequences. As discussed in later portions of this thesis, deregulation policies in both nations have begun to allow market forces to determine demand and supply levels for natural gas. Thus, deregulation should reduce the potential for inadvertent governmental interference in natural gas trade. Yet even in an atmosphere of decontrol, it must be recognized that the natural monopoly aspects of gas markets will remain regulated in both countries.

The guiding principle in the decontrol of natural gas markets should be to ensure that prices remain responsive to competition from fuel oil.[25] Through the end of the century, increasing volumes of low-cost Canadian imports are forecast to add to the general market pressure that will keep the overall price of natural gas low enough to keep levels of imported oil from rising drastically.[26] Free trade is critical to ensuring that Canadian natural gas supplies can be traded in U.S. markets unimpeded by discriminatory institutional barriers, and that Canadian gas can meet its fullest potential by competing with domestic gas sup-

18. Interview with Andrea K. Waldman, *supra* note 11.
19. *Id.*
20. U.S.-CANADA GAS TRADE REVIEW, *supra* note 2, at 43.
21. *Id.*
22. *Id.* at 9.
23. *Id.* at 10.
24. Buckley & Grammer, *supra* note 3, at 30-32.
25. U.S.-CANADA GAS TRADE REVIEW, *supra* note 2, at 43.
26. *Id.* at 16.

plies on an equitable basis.[27] There is some concern among domestic producers that United States policies that still continue some wellhead price controls and that other institutional disincentives for exploration and production place Canadian gas in a superior market position.[28]

## II. SHORTAGE AND SURPLUS: A UNITED STATES PERSPECTIVE

The role that Canadian gas imports play in the U.S. market is naturally tied to domestic supply and demand. Only ten of the continental United States produce more gas than they consume with Texas, Louisiana and Oklahoma contributing 78 percent of total domestic production.[29]

### A. *Deliverability Dilemma*

The extent of domestic availability is tracked by the U.S. Department of Energy according to a "deliverability" statistic.[30] Deliverability is determined by calculating the available capacity of major interstate pipelines to transport the volumes of natural gas that are under contract to their market areas.[31]

The future direction of deliverability in the U.S. is a highly controversial subject due to past regulatory intervention in the form of the Natural Gas Policy Act of 1978 (NGPA)[32] and the countervailing

27. Interview with Andrea K. Waldman, *supra* note 11.

28. Crow, *U.S. Producers Fear Market Losses to Canada With Trade Pact,* OIL & GAS J. April 4, 1988. The concerns of domestic producers are reflected through trade organizations such as the Independent Petroleum Association of America (IPAA) and the Independent Petroleum Association of Mountain States (IPAMS). *Id.*

29. NATURAL GAS TRENDS, *supra* note 9, at 71. The net producing states are Kansas, Louisiana, Montana, New Mexico, North Dakota, Oklahoma, Texas, Utah, West Virginia, and Wyoming. *Id.*

30. ENERGY INFORMATION ADMINISTRATION, U.S. DEPT. OF ENERGY, GAS SUPPLIES OF INTERSTATE NATURAL GAS PIPELINE COMPANIES (1985).

31. *Id.* All interstate pipeline companies reporting on FERC Form 15 "Interstate Pipeline's Annual Report of Gas Supply" project the annual volumes of natural gas expected to be deliverable from each domestic certificated source for each of the five years following the year of the report. Additionally, 36 major interstate pipeline companies are required by FERC to report a 20 year projection of the total annual volumes of natural gas including pipeline purchases and imports, deliverable from total year-end supplies. These deliverability forecasts are the reporting company's best year-by-year estimates of its capability to deliver present natural gas requirements from present supplies. Future load growth and increases in gas supply are not considered. The market requirements are only those that have been authorized at the end of the report year. Both firm and interruptible authorized gas requirements, however, are included. *Id.* at 105.

32. In November of 1978, the United States Congress adopted the Natural Gas Policy Act of 1978 (NGPA), 15 U.S.C. §§ 3301-3432 (1988).

The NGPA has been the subject of much comment and criticism because of the innovations developed by the industry's chief regulatory body, the Federal Energy Regulatory Commission. Fox, *Transforming an Industry by Agency Rulemaking: Regulation of Natural Gas by the Federal Energy Regulatory Commission,* 23 LAND & WATER L. REV. 113 (1988).

The NGPA appears to have accomplished what it was designed to do: Create drilling incentives that would alleviate the natural gas shortages that characterized the movement toward decontrol and greater competition undertaken by the Reagan Administration in its legislative proposals to Congress.[33] Additionally, through a series of administrative orders the industry's independent regulatory body, the Federal Energy Regulatory Commission (FERC), has sought to increase the competitiveness of natural gas against alternative fuels such as residual oil for industrial end-users, the "devintaging" of wellhead gas prices, and the encouragement of open-access transportation on interstate pipelines.[34]

A constant rate of production from proven domestic reserves of 200 trillion cubic feet (TCF) will supply 11 years of U.S. consumption.[35] However, deliverability is expected to decline more rapidly. Department of Energy figures forecast domestic deliverability to decline from 12.2 TCF in 1986 to 6.2 TCF by 1990.[36] A recent study by Cambridge Energy Research Associates sees the United States as "already committed to heavier reliance on imported natural gas . . ." in combination with storage and seasonal fuel switching in order to satisfy peak seasonal demands through the early 1990s.[37] In the late 1970s gas supply shortages had substantially narrowed the margin between interstate pipeline deliverability and total volume of sales. For example, in 1977 deliverability of contracted supplies exceeded sales by just 500 billion cubic feet (BCF).[38] This is sharply contrasted with figures for the next decade. During the period from 1982 to 1987, deliverability declined by one quarter but pipeline sales dropped by more than half.[39] This resulted in an estimated deliverability of 11.6 TCF in 1987, which was double the volume of pipeline sales for the same period.[40]

1. Evolution of the Spot Market

U.S. natural gas markets are becoming more dynamic and increasingly short-range in terms of commercial commitments. Furthermore, the spot market is so well developed that not only does the majority of natural gas move under these transactions but spot prices are reported on the following basis for key points in the transmission and distribution network:

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1970s. The NGPA helped increase gas well completions to a record of nearly 12,000 in 1981, up from 8,169 completions in 1975. Combined with lower consumption brought about by higher prices and recession, the increased level of drilling turned shortages into surpluses.

33. *See* H.R. 4604 & S. 2285, Natural Gas Policy Act Amendment of 1986 introduced in the House on April 16, 1986 and in the Senate on April 10, 1986; H.R. 1155 & S. 539, Trade Employment and Productivity Act of 1987 was introduced in both Houses of Congress on Feb. 19, 1987.

34. *See generally* Fox, *supra* note 32.

35. U.S.-CANADA GAS TRADE REVIEW, *supra* note 2, at 10.

36. GAS SUPPLIES OF INTERSTATE GAS PIPELINE COMPANIES, *supra* note 30, at 3.

37. NATURAL GAS TRENDS, *supra* note 9, at 1.

38. *Id.*

39. *Id.*

40. *Id.*

Production Areas

Appalachian

Mid-Continent

Texas-Offshore

Rocky Mountain

City - Gate

California

New York, New Jersey

Illinois, Indiana

Burner-Tip to Major Industrial Customers

Texas

Louisiana[41]

The spot market has grown rapidly in the last several years. This market growth is evident when comparing direct sales by interstate pipelines with the volumes transported over those systems. In 1987, total interstate natural gas pipeline sales fell by 1.4 TCF while transportation "on behalf" of third parties increased by 3.5 TCF.[42] Some market analysts believe that spot transactions may now account for over 40 percent of all natural gas marketed.[43] Another estimate placed the use of spot market sales as high as 60 percent.[44] This reflects the fundamental restructuring that is sweeping the natural gas industry. Spot sales are made on the basis of a 30-day bid with either buyer or seller able to terminate the relationship at the end of this period.[45] The growth of the spot market has been the primary cause of the dramatic shift from pipeline system sales to transportation volumes because spot sales prices are generally .30 to .35 per MMBTU lower than pipeline commodity rates.[46]

Imported natural gas from Canada has typically supplied between 4 to 5 percent of U.S. demand.[47] However, the decline in the average price for domestic and imported gas has made Canadian supplies more competitive. The first half of 1988 registered a rapid increase in

41. *Id.* at 77.
42. *Id.* at 81.
43. *Id.* at 74.
44. Telephone interview with Constance L. Buckley, Director, Natural Gas Division, Office of Fuels, Programs, Office of Fossil Energy (March 11, 1989).
45. *Id.*
46. *Canadian Gas Exports Rise 4% Above Year-Ago Levels,* NAT. GAS WKLY. March 6, 1989 at 7. Average long-term volumes were priced at $2.13/MMBTU in 1988, while spot gas sold for $1.75/MMBTU. *Id.*
47. U.S.-CANADA GAS TRADE REVIEW, *supra* note 2, at 42. The level of Canadian market production going to the U.S. has been about one third (27.8% to 38.6%) and in 1985 had an export earnings of $4 billion. *Id.*

imports.[48] Although natural gas imports from Canada have historically been a relatively small portion of all natural gas marketed, they are forecast to double by 1995 just to keep pace with current demand.[49]

2. Special Marketing Programs

The FERC began the United States movement towards short term or spot markets initially through Special Marketing Programs (SMPs) which were authorized through blanket certificates issued under Orders 234-B and 319 issued on July 28, 1982.[50] SMPs were developed for large, high-priority industrial end-users and electric utilities.[51] About 70 percent of industrial natural gas users have dual fuel capability and can switch between natural gas and oil as prices dictate.[52] In order to retain large-volume users in a volatile market, interstate pipelines argued that natural gas prices must be able to track any decline in oil prices.[53] As noted earlier, U.S. natural gas consumption fell by 7 percent between 1985 and 1986, simply because oil prices dropped more quickly than those of natural gas. Pipelines contended that many marketing opportunities with large volume industrial customers were lost because of the regulatory lag before FERC.[54]

The legitimacy of FERC's blanket SMP authorizations (5-10 years for Order 319 and 120 days under Order 234B) was challenged in the D.C. Circuit Court of Appeals in the case of *Maryland People's Counsel v. F.E.R.C.*[55] Plaintiffs contended that the blanket certificate programs facilitated price discrimination because the SMP would, "by insulating pipelines from the full shock of competition with suppliers of alternative fuels, . . . entrench the pipelines' power to extract monopoly profits."[56] The Court of Appeals found that FERC had failed to consider the anticompetitive effects of the SMPs and directed that the agency propose rulemaking to address the Court's concerns.[57] This resulted in FERC issuing a Notice of Inquiry which began the movement towards open access transportation on interstate pipeline systems.[58]

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48. NATURAL GAS DIVISION, OFFICE OF FUELS PROGRAMS, OFFICE OF FOSSIL ENERGY, U.S. DEPARTMENT OF ENERGY, IMPORTS, VOLUMES AND PRICES (1988).
49. *Id.*
50. 18 C.F.R. § 157 (1989).
51. *Id.*
52. NATURAL GAS TRENDS, *supra* note 9, at 8.
53. U.S.-CANADA GAS TRADE REVIEW, *supra* note 2, at 25.
54. *Id.*
55. 761 F.2d 780 (D.C. Cir. 1985).
56. *Id.* at 786.
57. *Id.* at 781-82.
58. The notice was issued in three phases. Issues related to transportation of natural gas in interstate commerce on behalf of nonowner shippers, i.e., those seeking transportation on pipeline systems in which they did not have an ownership interest were noticed at 50 Fed. Reg. 114 (1985). Comments regarding the other phases of the Notice of Inquiry on rate structure and design and financial implications for regulated pipelines were noticed at 50 Fed. Reg. 3801 (1985).

3. Interstate Pipelines Change Roles

Prior to the mid-1980s, the major interstate pipelines not only transported but purchased and resold the major portion of natural gas used in the United States.[59] This structure placed the interstate pipelines in the role of "gas merchant" as well as carrier. The "merchant" nature of pipeline activity, purchasing and reselling natural gas rather than only transporting it for third parties, deserves some discussion. Several reasons accounted for this integration of activities:

(1) principally, interstate pipelines had to stimulate a large volume market for natural gas as well as provide service;

(2) early pipelines were considered inherently unsafe due to leaky joints and buyers would not assume this liability;

(3) it was easier to finance pipeline construction by creating a direct relationship with the producer which guaranteed system through put; and

(4) true economy of scale was achieved, which could be passed on to the customer.[60]

The restructuring of the natural gas industry that has been brought about by deregulation has meant that interstate pipelines no longer dominate the market. Restructuring has allowed other parties such as producers and independent marketers, as well as pipeline affiliated marketers, to make direct sales to industrial end users and local distribution companies (LDCs).[61] Although there is a clear trend towards greater market reliance upon price responsive commercial relationships, the effect upon interstate pipelines from competition in the volatile short term market is only starting to be evaluated.[62] Critics contend that until the take-or-pay liabilities between interstate pipelines and gas producers are addressed directly by FERC, open access transportation under current rules is subject to challenge as retroactive rate making.[63]

4. Canadian Participation in the U.S. Spot Market

Market pressures caused the Canadian federal government to change its position on short-term sales. The early need for Canadian suppliers to play an aggressive role in the U.S. spot market was vividly illustrated when Pacific Gas & Electric (PG&E) indicated it would pur-

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59. NATURAL GAS TRENDS, *supra* note 9, at 81.

60. NATIONAL ENERGY BOARD, A REVIEW OF THE ROLE AND OPERATIONS OF INTERPROVINCIAL AND INTERNATIONAL PIPELINES IN CANADA ENGAGED IN THE BUYING, SELLING, AND TRANSMISSION OF NATURAL GAS, PIPELINE REVIEW PANEL ESTABLISHED PURSUANT TO CLAUSE 25 OF THE AGREEMENT AMONG THE GOVERNMENTS OF CANADA, ALBERTA, BRITISH COLUMBIA AND SASKATCHEWAN ON NATURAL GAS MARKETS AND PRICES OF 3L OCTOBER, 1985 at 3 (June, 1986).

61. NATURAL GAS TRENDS, *supra* note 9, at 7.

62. *Id.*

63. *See, e.g.*, Watkiss, *Deregulatory Myopia: Sacrificing the Filed Rate Doctrine and Rule Against Retroactive Ratemaking to Promote Competition in Gas Markets,* 42 Sw. L.J. 711 (1988).

chase roughly 200.0 MMCF/D of its supplies on the spot market.[64] To accommodate this plan, Canadian purchases under long-term contracts would decline unless the cost of those supplies was reduced accordingly. As a result of this threat, the Economic Regulatory Administration (ERA) allowed Albert & Southern Gas Co. to sell up to 100.0 MMCFD at $2.50 per MCF to PG&E in California.[65] Shortly thereafter, another Canadian supplier, Westcoast Transmission Company, Ltd., also sought approval for participation in U.S. spot markets. Its American marketing affiliate received approval from the ERA to import up to 50.0 BCF a year for two years.[66]

Canadian participation in the U.S. spot market is now common place. Over 25 firms have import approval for natural gas that trades solely on a short term basis.[67] Not only has the number of importers increased, volumes have grown dramatically reaching 1260 BCF in 1988.[68]

*B. Transportation Capacity Limitations*

There should be many long-term opportunities for Canadian gas in U.S. markets as domestic deliverability declines. The only pricing criteria that must be adhered to from a U.S. standpoint is that gas will have to be competitive with residual fuel oil.[69] Considering the adequate quantities of Canadian gas and U.S. market demand, this should not present an insurmountable hurdle. In the 1990s, demand for Canadian gas should easily surpass the 2 TCF per year mark.[70] The major problem that can be anticipated at this stage is whether or not sufficient pipeline capacity exists to deliver the necessary quantities of gas to U.S. markets. In their 1988-89 review of natural gas trends, Cambridge Energy Associates stated:

> The longer-term future of Canadian gas exports depends on the fate of the proposed expansion of the Pacific Gas Transmission Line and on the outcome of the 'open season' for pipeline proposals in the northeast.[71]

Without increased transportation capacity, gas sales can only be expanded during off-peak periods, as export capacity during peak periods is already constrained.[72]

Demand levels for imported natural gas vary geographically in the U.S. The Northwest and California have been strong markets.[73] Mid-

64. Pacific Gas Transmission Co., 1 ERA (CCH) ¶ 70,574 (1984) (granting conditional approval and providing for further hearing).
65. *Id.* at ¶ 72,324.
66. Westcoast Resources, Inc., 1 ERA (CCH) ¶ 70,606 (1985).
67. IMPORTS, VOLUMES AND PRICES, *supra* note 48.
68. *Id.*
69. U.S.-CANADA GAS TRADE REVIEW, *supra* note 2, at 43.
70. *Id.* at 13.
71. NATURAL GAS TRENDS, *supra* note 9, at 99.
72. *Id.*
73. Interview with Andrea K. Waldman, *supra* note 11.

western demand has been reduced, only to be offset by growth in the Northeast.[74]

Figure 2 shows the points of interconnection between U.S. and Canadian pipeline systems. Because of physical bottlenecks and fluctuating seasonal demand levels at the various export points, more pipeline construction will be necessary if gas is to reach U.S. markets.[75] There is a current maximum of about 1.7 TCF of capacity on pipeline systems that transport Canadian natural gas to U.S. markets.[76] By the end of the century, the maximum export demand is projected to be 2.4 TCF.[77]

1. California Projects

Three different pipeline proposals are currently competing for expanded natural gas service to California markets, particularly to the enhanced oil recovery operations in Kern County near Bakersfield.[78] The projects include similar proposals by Kern River Gas Transmission Company (Kern River) and the Wyoming-California Pipeline Company (WyCal). Both pipelines would be built from southwestern Wyoming across Utah and Nevada, a distance of approximately 900 miles.[79] The Kern River Project would cost approximately $800 million and would be capable of delivering 700 MMCF/d of which half would come from Canadian sources.[80] The WyCal Project would cost about $665 million and project sponsors have not identified specific gas sources.[81] The third proposal was submitted by Mojave Pipeline Company and would cross western Arizona.[82] The pipeline would be 388 miles in length and cost $300 million to construct.[83] Natural gas would come from Texas and New Mexico as well as Canada.[84]

The three companies have applied to FERC for certification.[85] In January, 1989, WyCal received conditional approval to proceed with construction under the expedited procedures available to open access pipelines.[86] Interestingly, because FERC did not treat these projects as mutually exclusive, both Kern River and Mojave continued to compete with WyCal to obtain market support.[87]

74. *Id.*
75. U.S.-CANADA GAS TRADE REVIEW, *supra* note 2, at 13.
76. *Id.*
77. *Id.*
78. Mojave Pipeline Company; Kern River Gas Transmission Company; Northwest Pipeline Corporation; El Paso Natural Gas Company; Transwestern Pipeline Company; and Wyoming-California Pipeline Company, 46 F.E.R.C. (CCH) ¶ 61,029 (1989).
79. Interview with John Smith, Manager, Joint Ventures, Northwest Pipeline Corporation, in Salt Lake City, Utah (March 5, 1989).
80. *Id.*
81. *Id.*
82. Mojave Pipeline Co., 35 F.E.R.C. (CCH) ¶ 61,199 (1986).
83. *Id.*
84. *Id.*
85. *Id.*
86. Wyoming-California Pipeline Company, 45 F.E.R.C. (CCH) ¶ 61,353 (1988).
87. Interview with John Smith, *supra* note 79.

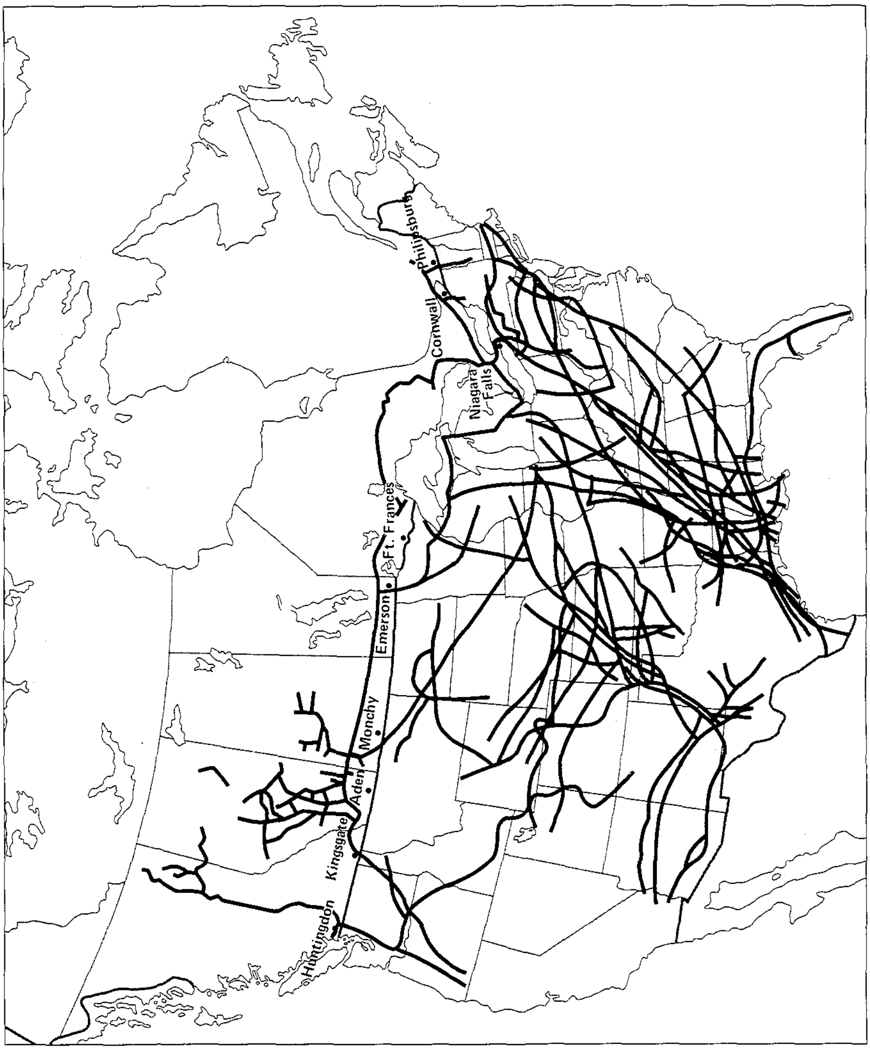


**Figure 2. United States Interstate and Canadian Interprovincial Pipelines.**

Most recently, Kern River, Mojave, and Southern California Gas Company (SoCal) announced an agreement in principle under which the parties would agree that Kern River and Mojave would build and operate separate pipeline systems that would converge at Barstow, California.[88] A 42-inch pipeline would extend past that point and would be owned and operated by Mojave. The combined downstream capacity of this system would be 11,000 MMCF/D and would be divided 64 percent to Kern River and 36 percent to Mojave.[89] After 22 years of operation SoCal would have the option to purchase the California extension of the combined pipeline system. Industry analysts believe that the union of these former rivals now makes the combined Mojave-Kern River project the forerunner in the interstate pipeline race to provide service for enhanced oil recovery as well as transportation of California utilities.[90]

Another California oriented pipeline project has been announced by Amoco Canada Petroleum Company, Ltd., Mobil Oil Canada, Petro-Canada, Inc. and Shell Canada, Ltd. for the construction of the Altamont Gas Transportation Project.[91] The project sponsors represent 31 percent of all Canadian natural gas production.[92] The proposed Altamont project would originate at the Alberta border and would interconnect with either Kern River or WyCal at Opal, Wyoming. The system would be designed to be 30 inches in diameter and have the capacity of moving 700 MMCF/D of natural gas through its 1615 mile system.[93] Construction costs are estimated to be $580 million and the project would begin start-up in 1993-1994.[94]

Sponsors in the U.S. have proposed three major projects potentially in competition with each other that could transport incremental volumes of Canadian gas into the Northeast U.S. beginning in the latter part of this decade.[95] These proposals, which involve the construction of new pipelines as well as installation of additional compression on existing systems, are described in the following sections.

2. Ohio Interstate Pipeline

ANR Pipeline, in partnership with Northern Natural Gas, is sponsoring the construction of the Ohio Interstate Pipeline Company (OIPC). The OIPC pipeline project is estimated to cost $1.1 billion, and would be a U.S. west-to-east pipeline with approximately 373 miles of line to be built from Defiance, Ohio to Leidy, Pennsylvania.[96] The cost of

88. NEW MEXICO OIL CONSERVATION DIVISION, 3 GAS MARKETING NEWSLETTER, at 5 (July 1989).
89. *Id.*
90. *Id.*
91. THE ALTAMONT GAS TRANSPORTATION PROJECT, PROJECT SUMMARY (May 23, 1989).
92. *Id.*
93. *Id.*
94. *Id.*
95. Northeast U.S. Pipeline Projects, 40 F.E.R.C. (CCH) ¶ 61,087 (1987).
96. MERRILL LYNCH, PIERCE, FENNER & SMITH, NATURAL GAS MONTHLY: A CANADIAN PERSPECTIVE at 8 (Oct. 1985).

this part of the OIPC is estimated at $505.4 million. Additionally, a 300-mile expansion of the Northern Border Pipeline would be undertaken from Ventura, Iowa to Sandwich, Illinois, to interconnect with the existing ANR system. Compression would be increased for the existing 822-mile line from the Monchy, Saskatchewan entry point to Ventura with this part of the project estimated to cost $560 million.[97]

Natural gas produced in Alberta would flow through the Foothills Pipe Lines system to the entry point at Monchy. Once in the United States, Northern Border Pipeline would carry the gas to Sandwich into the ANR system, then to Defiance, Ohio. At Defiance, the natural gas would enter OIPC for final delivery, to Leidy and to LDCs and industrial end users.[98]

3. TransCanada Expansion

TransCanada Pipelines Limited ("TransCanada") currently owns and operates a large diameter pipeline system that is 2,700 miles in length.[99] This system extends from Saskatchewan to Quebec and interconnects with the interstate pipeline systems operated in the United States by Midwestern Gas Transmission Company, Great Lakes Gas Transmission Company, Tennessee Gas Transmission Company, Vermont Gas Systems, Inc. and Niagara Gas Transmission Limited.[100]

TransCanada has proposed an alternative pipeline project to OIPC that would include a $625 million expansion of its existing system as well as a $350 million expansion of the Great Lakes Gas Transmission Company, of which TransCanada owns 50 percent (ANR owns the other half). This proposal would involve an estimated 278 miles of new pipeline plus an additional 25 compressor units. Construction would take 3 years. When completed, the expansion would be capable of transporting 885 MMCF/D, with half of the natural gas to be transported on the TransCanada system and the other half through the Great Lakes system of Niagara Falls Gas Transmission, Ltd., from which point it would be carried to Leidy, Pennsylvania. To move the gas to Leidy, construction of the 161-mile Niagara Interstate Pipeline system would be required at an estimated cost of $322 million. Niagara Interstate would be owned by Tennessee Gas, Transcontinental Gas Pipeline, and TransCanada (each with a 29 percent interest) and Texas Eastern (with a 13 percent interest) and would have a capacity of 1.3 BCF/D.[101]

4. MidContinental Transportation System

The third competing project is sponsored by Natural Gas Pipeline Company of America (NGPL).[102] This project has the lowest estimated

97. *Id.*
98. *Id.*
99. *Id.* at 8-9.
100. *Id.*
101. *Id.*
102. *Id.*

cost of about $530 million. The sponsor anticipates carrying imported natural gas to market at a transportation charge of roughly a third of that projected by the two others by virtue of various exchange agreements the company is working on. The basic objective of the project is to bring Alberta gas to NGPL's market area to displace Gulf Coast gas supplies, which could be diverted to other pipelines serving the eastern market. Those pipelines, all of which would be involved in the other projects, would be Tennessee Gas, Transcontinental Gas Pipeline, Texas Eastern, Boundary Gas Company, and Algonquin Gas Transmission. As in the case of the OIPC, gas would be transported through the Northern Border Pipeline to Ventura, Iowa where it would be necessary for NGPL to build a 146-mile line from Ventura to its existing pipeline in Harper, Iowa. An additional pipeline of about 185 miles would be constructed from St. Jo, Texas to Atlanta, Texas to interconnect the company's two major pipelines. The interconnected system would be capable of transporting up to 1.1 BCF/D, even though the project seeks authority to transport 871.8 MMCF/D. NGPL has yet to work out transportation agreements with the other companies, and several of those might be unwilling to negotiate with NGPL because they are participating in the Niagara Interstate Pipeline Company.[103]

Financial analysts have questioned whether any of the three projects can be constructed given the increased level of risk in the industry and rapidly declining prices for natural gas.[104] With gas markets becoming more competitive, and future gas pipeline returns increasingly dependent upon a company's ability to market rather than on expansion of rate base, pipeline projects that propose to import additional supplies into the United States are seen as extraordinarily risky. The expedited certification under Order 500 is seen as a mixed blessing because all financial risks are assumed by the sponsors rather than sharing them with customers through demand charges and minimum bills.[105] Projects may be funded, but they are expected to be financed at above-average rates, and pipeline companies may have to put more equity into these systems instead of totally utilizing project financing.

These projects and the other smaller pipeline expansion proposals to serve the Northeast have major obstacles to overcome. These include outright opposition from environmental groups over route location and from fuel oil distributors who fear the market disruption from natural gas.[106]

The success of the projects will require coordination between Canadian and American regulatory agencies.[107] Considering the competing features of these projects, compromise and cooperation in the private sector will also be necessary if the expansions are to be completed in a timely manner.

103. *Id.*
104. *Greater Imports of Canadian Gas to the U.S. Are Stalled, supra* note 7.
105. NATURAL GAS TRENDS, *supra* note 9, at 4.
106. *Greater Imports of Canadian Gas to the U.S. Are Stalled, supra* note 7.
107. *U.S., Canada Need Closer Ties to Make Pipe Dreams a Reality,* NAT. GAS WKLY. March 6, 1989 at 12, 15.

## III. MARKET RESPONSIVENESS: A CANADIAN PERSPECTIVE

At current levels of production Canada has a 34-year reserves-to-production ratio (R/P) compared to a 9.8 reserve life in the lower 48 states.[108] Even with this impressive supply position, market prices are the controlling factor in setting demand. Because exports to the United States have accounted for 1/3 of total annual Canadian gas production, changes in export prices have a tremendous impact on production levels.[109] This is what economists call "elasticity of demand," i.e., lower prices result in greater levels of demand.

### A. *Lessons of Elasticity*

Prices for imported natural gas began to climb in 1980. As illustrated in Figure 3, from $1.75 per million BTU (MMBTU) in 1977, the price of imported Canadian gas jumped to $2.15 in 1978, then to $4.29 in 1980, and peaked at $4.94 in 1982. During this period, the Canadian government discovered just how elastic natural gas demand was in the United States export market. As prices topped the $4.00 mark, export volumes began to decline from 1.0 TCF in 1979 to a low of 3.5 BCF in 1983. Figure 3 shows that with a reduction in the average price to approximately $4.09 per MMBTU in 1984 and $3.30 in 1985, volumes recovered to an estimated 755 BCF and 926 BCF, respectively. In 1988, declining prices resulted in a record 1260 BCF in Canadian imports. A rebound in sales coincided with a needed change in lowering Canada's official export price. The National Energy Board had previously set the export price at the cost of natural gas delivered to customers in Toronto, Ontario, hence the reference to "Toronto city-gate" pricing. The first policy change came in April and July of 1983 when Canada initially reduced the border price from $4.94 to $4.40 per MMBTU.[110]

### B. *Contract Renegotiations*

The major breakthrough occurred in July 1984, when the NEB announced that it would allow exporters to negotiate contract prices.[111] Numerous contracts were renegotiated according to these guidelines for the 1984-85 contract year, thus setting the stage for a rebound in Canadian exports to record levels of 926 BCF.

Eliminating the Toronto floor price in favor of a more flexible negotiated pricing policy that reflected regional transportation and

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108. NATURAL GAS TRENDS, *supra* note 9, at 96.
109. *Id.*
110. U.S.-CANADA GAS TRADE REVIEW, *supra* note 2, at 28.
111. NATIONAL ENERGY BOARD, MEMORANDUM TO ALL EXPORT LICENSE HOLDERS: REGULATORY PROCEDURES AND INFORMATION REQUIREMENTS FOR APPLICANTS FOR CHANGES TO EXISTING NATURAL GAS EXPORTS SALES CONTRACTS AND LICENSES (Oct. 2, 1984). This program included a so-called "volume related incentive price" (VRIP) for incremented volumes, so if an importer took 50 percent of annual licensed volumes, additional levels would be priced at $3.40/MMBTU. *Id.*

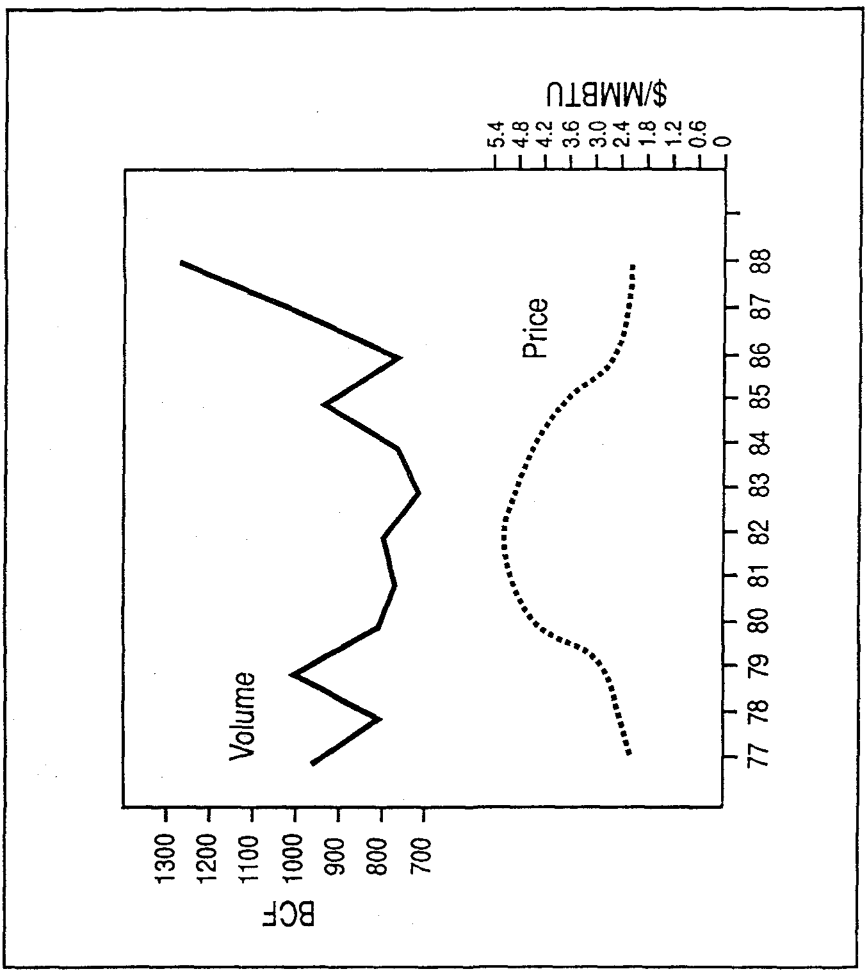


Figure 3. Natural Gas Import Prices and Volumes 1977-88.

other factors is cited as a major objective by Alberta and many Canadian producers in reaching their goal to make imported natural gas more competitive in U.S. markets.[112]

*C. Market Shake Out and Rebound*

Both prices and volumes began to decline for Canadian natural gas imports after 1985. Total volumes had dropped to 748 BCF that year.[113] Furthermore, import prices declined steadily and were under $2.00/MMBTU in December, 1986.[114]

These declines were attributed to both a slower response by imported natural gas suppliers to rapidly declining domestic prices as well as a lack of Canadian access to developing spot or short-term markets.[115] United States domestic consumption also declined during this period. However, Canadian imports decreased more dramatically, in part because traditional markets for Canadian gas in California and the Great Lake states experienced a greater reduction in demand.[116] An additional factor contibuting to this decline was the pressure that U.S. gas producers put on interstate pipelines to honor take-or-pay obligations. This approach resulted in producers forgiving a portion of such contract payments on the condition that the gas-merchant pipelines would tender their production in the spot market which had begun to play a new role as competition with alternate fuels.[117] Overall, NEB estimated that United States importers only took 40 percent of long-term contract volumes in 1986.[118] As a result, total Canadian gas export revenues fell by 36 percent in 1986.[119]

Import prices have stabilized between $2.00 to $2.50/MMBTU for 1987 and 1988.[120] This is only part of the picture. The most revealing indicators are the total export volumes for those years which were up sharply to new record levels of 989 BCF in 1987 and 1260 BCF in 1988.[121]

This rebound in the market for Canadian natural gas parallels key policy adjustments that occurred in November, 1986 when the Agreement on Natural Gas Markets and Prices replaced the national government-administered pricing structure with a market oriented sys-

112. U.S.-CANADA GAS TRADE REVIEW, *supra* note 2, at 28.
113. IMPORTS, VOLUMES AND PRICES, *supra* note 48.
114. *Id.*
115. R. Priddle, Assistant Deputy Minister for Energy, Mines and Resources, Conference on Marketing Canadian Natural Gas in the United States, Executive Enterprises, Inc. (Feb. 7, 1985). Nationally, the new Conservative government's energy policy objectives included economic renewal; energy self-sufficiency; Canadian participation; a fair balance of interest between sectors and regions and the provisions of a stable energy planning environment. *Id.*
116. U.S.-CANADA GAS TRADE REVIEW, *supra* note 2, at 10.
117. *Id.*
118. NATURAL GAS TRENDS, *supra* note 9, at 9496.
119. *Id.*
120. IMPORTS, VOLUMES AND PRICES, *supra* note 48.
121. *Id.*

tem.[122] Equally important, the flexibility to compete in the spot market was achieved when the NEB determined that advanced regulatory approval for short-term sales was no longer required.[123] These developments are discussed in greater detail in Chapter 5.

*D. New Canadian Dominance*

Canada's continual flexibility in its export pricing policies has made it the dominant source of U.S. imported natural gas. Other traditional natural gas exporters have conceded the field to the Canadians. Algeria has been unwilling to reduce its prices to United States market-clearing levels.[124] Rather than compete in the United States, Mexico has elected to export its crude oil and dedicate natural gas for local consumption.[125] The Canadian natural gas market is openly acknowledged as having achieved a greater degree of deregulation than markets in the U.S.[126]

## IV. THE LEGAL AND INSTITUTIONAL ENVIRONMENT IN THE UNITED STATES

The natural gas industry in the United States has been heavily regulated for the past 50 years.[127] The extent of this regulation is evidenced by the comprehensive nature of regulatory control from wellhead production to the sale, transportation and marketing of natural gas. Legislation signed into law on July 31, 1989 eliminates all wellhead price controls originally created under Title I of the NGPA.[128]

*A. Constitutional and Statutory Underpinnings*

The Commerce Clause of the Constitution of the United States grants Congress the power to regulate foreign commerce.[129] Furthermore, the U.S. Supreme Court has indicated that, unlike interstate commerce, there is no implied or reserved power in the states over international commerce and that the foreign commerce power of the federal government is even more potent than its control over interstate commerce.[130]

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122. MINISTRY OF ENERGY MINES AND RESOURCES, AGREEMENT ON NATURAL GAS MARKETS AND PRICES (1986).

123. *Id.* at 3-5. As of November 1, 1986 Canadian regulatory bodies no longer require that they give prior approval of export prices, but they do monitor both domestic and export prices quarterly. *Id.*

124. U.S.-CANADA GAS TRADE REVIEW, *supra* note 9, at 11-12.

125. *Id.*

126. Interview with R.A. Reinstein, Director, Energy and Natural Resources, Office of the United States Trade Representative, in Washington, D.C. (Oct. 22, 1987).

127. Watkiss, *supra* note 63, at 714-18.

128. Natural Gas Wellhead Decontrol Act of 1989, Pub. L. No. 101-60, 103 Stat. 157 (1989). Immediate price decontrol applied to: (1) contracts which had expired or terminated before the date of enactment; (2) contracts which were entered into after the date of enactment; (3) contracts which expired or terminated after the date of enactment; and (4) contracts which expressly provided that sales would be decontrolled by their own terms. Newly spudded wells under sales contract which were in effect on the date of enactment would have prices decontrolled at the earlier of contract expiration of May 15, 1991. *Id.*

129. U.S. CONST. art. I, § 8.

130. Japan Line Ltd. v. County of Los Angeles, 441 U.S. 434, 448-51 (1979).

Statutorily, both the importation and exportation of natural gas is regulated by the Natural Gas Act of 1938 (NGA).[131] Specific authority over natural gas importation is contained in Section 3 of the NGA, which requires prior federal approval to "import any natural gas from a foreign country . . . ."[132] Although delegation of this authority was originally vested in the Federal Power Commission (FPC), now the Federal Energy Regulatory Commission (FERC), Section 3 of the NGA has been administered by the Economic Regulatory Administration (ERA) of the Department of Energy (DOE) since 1977.[133] Due to a 1989 internal reorganization, the Office of Fuels Programs in the Office of Fossil Energy now administers the imported natural gas program, which includes pipeline and liquified natural gas.[134]

The legislative history of the NGA reveals that Congressman Rayburn had unsuccessfully introduced a measure that would have extended rate and certificate controls to natural gas moving in foreign commerce just as it had done for the interstate transmission of natural gas.[135] Ten years after the NGA's enactment, the D.C. Circuit Court of Appeals ruled that imports and exports of natural gas are not subject to Section 7 certificate requirements under the NGA.[136] Any uncertainty about the scope of NGA authority over imports was eliminated by the *Border Pipe Line Co.* decision.

*B. Regulated by Two Masters: ERA and FERC*

The decisions of two United States agencies may affect imports of natural gas into the United States. First, the Economic Regulatory Administration (ERA), a part of the DOE, has authority to approve or disapprove all imports.[137] The ERA also approves the point of entry into the U.S. in cases where no new transportation facilities in the U.S. are contemplated.[138]

Second, the Federal Energy Regulatory Commission (FERC), an independent agency under the umbrella of DOE, directly affects imports through its approval of facility siting and rates set for natural gas transportation and sale in the United States.[139] Because the United States natural gas industry has been so heavily regulated under the NGA and NGPA, FERC regulations and decisions understandably have had major

131. 15 U.S.C. §§ 717-717z (1988).
132. *Id.* § 717b.
133. 42 U.S.C. § 7172(f) (1982 & Supp. V 1987) ("No function described in this Section which regulates the exports or imports of natural gas . . . shall be within the jurisdiction of the Commission unless the Secretary assigns such a function to the Commission.").
134. 54 Fed. Reg. 11436 (1989) (DOE Delegation Order No. 0204-127).
135. Border Pipe Line Co. v. Federal Power Comm'n, 171 F.2d 149, 151 (D.C. Cir. 1948) (denying FPC's assertion that its jurisdiction under the NGA extended to interstate pipeline exporting gas into Mexico).
136. *Id.* at 152.
137. *See* DOE Delegation Order Nos. 0204-25 and 0204-26, 43 Fed. Reg. 47,769-72 (1978). Current delegation authority is pursuant to DOE Delegation Order No. 0204-111, 49 Fed. Reg. 6,690 (1984).
138. 10 C.F.R. § 590 (1988).
139. 18 C.F.R. § 153 (1988).

effects on natural gas imports. Regulation of the sale and resale of natural gas in interstate commerce has traditionally centered on the jurisdiction of the FPC and FERC under the NGA to: (1) issue certificates of public convenience and necessity; and (2) set rates. Foreign commerce is outside the scope of the NGA in these regards.[140] The regulation of interstate transportation and sale of natural gas by the FERC has major ramifications for imports. For example, Canadians have claimed that FERC Opinion No. 256 and Order 380, regarding the pass-through of fixed production costs in the demand charge component of contract prices, disrupted freely negotiated private sector contracts and had the effect of extended U.S. rate jurisdiction to Canada.[141]

1. ERA Import Approval Policy

The FPC reviewed import application under Section 3 of the NGA, according to the standards of Section 7 certificate proceedings.[142] Perhaps the most significant provision in the NGA is the statutory presumption contained in Section 3 in favor of the import or export.[143] It was the general practice for the FPC to interpret 15 U.S.C. section 717b to require a finding that:

1. The price was reasonable;
2. Underutilized facilities would be used;
3. Supplementary natural gas would be made available without constructing new facilities; and
4. The imported gas would assist in meeting seasonal shortages.

Unless the FPC found that the import was inconsistent with the public interest, the authorization was issued.[144]

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140. Compania de Gas de Nuevo Laredo, S.A. v. Federal Energy Regulatory Comm'n, 606 F. 2d 1024, 1029 n. 6 (D.C. Cir. 1979). The NGA defines "interstate commerce" as being "commerce between any point in a State and any point outside thereof, or between points within the same State but through any place outside thereof, but only insofar as such commerce takes place within the United States." 15 U.S.C. § 717a(7) (1988).

141. Natural Gas Pipeline Co. of America, 37 F.E.R.C. (CCH) ¶ 61,215 (1986), *reh'g denied,* 39 F.E.R.C. (CCH) ¶ 61,218 (1987). Order 256 shifts back some of the risk of under recovery of the full Canadian demand charge to the pipeline and away from its local distribution company customers. Under the Order, the effectively higher commodity charge must now be recovered on sales volumes meaning that incremental sales would not be as attractively priced as they were under the "as billed" pass-through terms of the import agreement. The Canadian government contended that these orders undermined the principle of respect for upstream jurisdictions which they said should have been observed on the same basis that FERC respects state jurisdiction over interstate rates.

142. Distrigas Corp. v. Federal Power Comm'n, 495 F.2d 1057, 1064 (D.C. Cir. 1974) (if necessary, Section 7 standards for public convenience and necessity could be imposed under Section 3 requirements for protection of the public interest), *cert. denied,* 419 U.S. 834 (1974).

143. Cia Mexicano de Gas, S.A. v. Federal Power Comm'n, 167 F.2d 804, 806 (5th Cir. 1948); *see also* Michigan Consolidated Gas Co. v. Federal Power Comm'n, 246 F. 2d 904 (3d Cir. 1957), *cert. denied,* 355 U.S. 894 (1957).

144. Tennessee Gas Transmission Co., 26 F.P.C. 860, 864 (1961).

The institutional trend toward greater liberalization of natural gas imports was inaugurated in 1977 with the enactment of the Department of Energy Organization Act.[145] Section 402(f) of the enabling legislation specifically provided that:

> No function described in this section which regulates the exports or imports of natural gas or electricity shall be within the jurisdiction of the Commission unless the Secretary assigns such a function to the Commission.[146]

FERC has stated that its authority over exports (and presumably imports) delegated by the Secretary of Energy "under Section 3 of the NGA . . . is only by analogy to Section 7, and not pursuant to Section 7."[147]

This assignment of authority for approving natural gas imports from the FPC to DOE has not gone uncriticized. One commentator thought the transfer of authority to DOE was inconsistent with the quasijudicial decision making provisions of the Administrative Procedures Act.[148] Other authors have reviewed the unique status of imported natural gas under a "lightened regulatory hand" as permitting Canadian supplies to be "increasingly judged on their economic merits . . . [as] the market begins to reach equilibrium."[149]

In a series of orders, the Secretary of Energy delegated responsibility for implementing Section 3 of the NGA to the ERA.[150]

2. Application Proceedings

The current import approval guidelines were issued in February, 1984 under the heading "New Policy Guidelines and Delegation Orders from Secretary of Energy to Economic Regulatory Administration and Federal Energy Regulatory Commission Relating to the Importation of Natural Gas."[151] They stress market responsiveness, need, and competitiveness in the importer's market, both for the present and future sales. These guidelines are discussed at greater length in following sections of this Chapter.

An import proceeding is initiated upon filing an application for authorization with the ERA's Natural Gas Division. In order to complete processing, the application is submitted at least 60 days in advance

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145. 42 U.S.C. §§ 7101-7375 (1982).
146. 42 U.S.C. § 7172(f) (1982).
147. Yukon Pacific Corp., 39 F.E.R.C. (CCH) ¶ 61,216 at 61,759 (1987); *see also*, Distrigas Corp. v. Federal Power Comm'n, 495 F.2d 1057 (D.C. Cir. 1974); Border Pipe Line Co. v. Federal Power Comm'n, 171 F.2d 149 (D.C. Cir. 1948); Wisconsin Gas Co. v. Federal Energy Regulatory Comm'n, 770 F. 2d 1144, (D.C. Cir. 1985), *cert. denied*, 106 S.Ct. 1969 (1986).
148. Note, *Imported Natural Gas Conflicts Between International Politics and Regulatory Safeguards*, 15 J. INT'L L. & ECON. 431 (1981).
149. Buckley & Grammer, *supra* note 3, at 39.
150. *Id.* at 29.
151. DOE Delegation Order No. 0204-111, 49 Fed. Reg. 6,690 (1984).

of the date of first delivery for the proposed import; however, "requests for expedited treatment will be considered for good cause."[152]

An application is formally filed as of the date and time of receipt stamped on the filing. At such time, the application is assigned a docket number which is referenced on any petition, motion, answer, or other document subsequently filed in the proceeding.[153]

In the course of processing the application, a decisional record is developed through written responses and comments, and, as required, through oral presentations.[154] Additional trial-like hearing procedures for presenting evidence and obtaining information may be requested as necessary to fully develop the facts and issues on which the decision will be made.[155]

After notice of the application is published in the *Federal Register,* 30 days usually are allowed for filing motions to intervene, protests, or comments on the proposal.[156] Subsequent answers to motions for intervention or protest must be submitted within fifteen days of the initial filing.[157] A final opinion and order may be issued prior to the expiration of the answer period either: (1) if no party has requested additional procedures; or (2) if the Administrator decides that additional proceedings are not required.[158] Interim Orders may be issued on a shorter schedule if required by emergency conditions.[159]

After the close of either the public comment period or the response period, the Administrator determines whether additional procedures are required.[160] In deciding what additional procedures are required the ERA has favored informal hearings over full evidentiary proceedings.[161]

Either a conditional order or a final order will be issued based upon a review of the record and stating a decisional summary and order.[162] If the order denies the requested authorization or includes material conditions, the parties will be advised of the reasons for the decision, as will other organizations and state and local officials with a proprietary, financial, or other special interest in the outcome of a proceeding.[163] This does not include federal agencies or foreign govern-

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152. *See generally,* NATURAL GAS DIVISION, ECONOMIC REGULATORY ADMINISTRATION, PROCEDURES FOR FILING AND PROCESSING AN APPLICATION BEFORE THE ECONOMIC REGULATORY ADMINISTRATION TO EXPORT OR IMPORT NATURAL GAS UNDER SECTION 3 OF THE NATURAL GAS ACT.
153. 10 C.F.R. § 590.106 (1988).
154. *Id.* § 590.312.
155. *Id.* § 590.310-13.
156. *Id.* § 590.205.
157. *Id.* § 590.302.
158. *Id.* § 590.316.
159. *Id.* § 590.403.
160. *Id.* § 590.314.
161. Inter-City Minnesota Pipelines Ltd., Inc., 1 ERA (CCH) ¶ 70,508 (1980).
162. 10 C.F.R. § 590.402 (1988).
163. *Id.* § 590.404.

ments and their representatives unless they are a formal intervening party to the proceeding.[164]

It is interesting to note that the rule prohibiting off-the-record communications excludes general background discussions about an entire industry or market, even though they may relate to the merits of a specific case.[165] The ERA has interpreted the exclusion on ex parte communication to mean:

> Discussions with foreign governments are also excluded from the rule because the agency must be able to conduct confidential discussions on international energy issues.[166]

ERA rules and regulations do not state a specific application format. Nevertheless, the preferred sequence for presentation of the facts supporting an application is as follows:

1. The exact legal name of the applicant, and the ERA docket number if the application relates to an existing docket;

2. The name, title, and post office address of the person to whom correspondence regarding the application shall be addressed (a maximum of two persons may be identified for the official service list);

3. "[A] statement describing the action sought from the ERA and the justification for such action, including why the proposed action is not inconsistent with the public interest . . .";

4. The identity of all participants in the transaction, "including the parent company, if any . . .," and the names of any corporate or other affiliations among the participants;

5. "The scope of the project, including the volumes of natural gas involved, the dates of commencement and completion of the proposed import or export and the facilities to be utilized or constructed . . . .";

6. "The source and security of the natural gas supply to be imported or exported, including contract volumes and a description of the gas reserves supporting the project during the term of the requested authorization . . . .";

7. "The terms of the transaction, such as take-or-pay obligations, make-up provisions, and other terms that affect the marketability of the gas . . . .";

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164. Interview with Constance L. Buckley, Director, Natural Gas Division, Economic Regulatory Administration, Department of Energy, in Washington, D.C. (Oct. 21, 1987).

165. 10 C.F.R. § 590.108 (1988).

166. PROCEDURES FOR FILING AND PROCESSING AN APPLICATION BEFORE THE ECONOMIC REGULATORY ADMINISTRATION TO EXPORT OR IMPORT NATURAL GAS UNDER SECTION 3 OF THE NATURAL GAS ACT, *supra* note 152, at 4.

8. "The provisions of the import arrangement that establish the base price, volume requirements, transportation and other costs, and allow adjustments during the life of the project, and a demonstration as to why the import arrangement is and will remain competitive over the life of the project and is otherwise not inconsistent with the public interest . . . .";

9. "For proposed imports, the need for the natural gas by the applicant or the applicant's prospective customers, including a description of the persons expected to purchase the natural gas . . . .";

10. "The potential environmental impact of the project . . . ."; and

11. A statement as to whether the same or a related matter is being considered by any other part of DOE, including the FERC, or any other federal agency or department and, if so, the identity of the matter and the agency or department.[167]

Additionally, two other exhibits should accompany the application. Exhibit A should be a statement, including a signed opinion of counsel, showing that the exportation or importation of natural gas is within the corporate powers of the applicant, and that the applicant has complied with State laws and with the rules of regulatory authorities in the state or states in which the applicant operates.[168]

Exhibit B should contain a copy of all relevant contracts and purchase agreements (completed, signed contracts may be submitted after the date of application if necessary).[169]

3. Scope of ERA Review

The fundamental determination that the ERA Administrator must make under DOE Delegation Order No. 0204-111 is whether an import is inconsistent with the public interest within the meaning of Section 3 of the NGA.[170] This decision takes into consideration other issues, including competitiveness of the import, need for the natural gas, and security of supply.[171]

The preambles to the 1984 policy guidelines and Delegation Orders 0204-111 and 0204-112 discuss how the relevant issues will be examined. The following approach will be taken in reviewing an application:

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167. 10 C.F.R. § 590.201 (1988).
168. *Id.*
169. *Id.*
170. NEW POLICY GUIDELINES AND DELEGATION ORDERS FROM SECRETARY OF ENERGY TO ECONOMIC REGULATORY ADMINISTRATION AND FEDERAL ENERGY REGULATORY COMMISSION RELATING TO THE REGULATION OF IMPORTED NATURAL GAS, 49 Fed. Reg. 6,684, 6,690 (1984).
171. *Id.*

*The competitiveness of the import[.]*

The terms and conditions of the gas purchase contract, taken together, must provide a supply of gas that the importer can market competitively over the term of the contract. The contract arrangement must be sufficiently flexible to permit pricing and volume adjustments, as required by market conditions and available competing fuels, including domestic natural gas. Contract flexibility is a function of certain provisions which may include, but are not limited to: the volume of gas under contract, base price, price review or adjustment mechanisms, take-or-pay obligations, make-up provisions, length of the contract, and other terms which may affect marketability of the gas. No prescribed set of provisions are being dictated as determinative of contract flexibility, allowing the importer to negotiate the import arrangement it considers necessary for the gas to remain marketable over the life of the contract. The importer will be required to demonstrate that the provisions in the proposed import arrangement, collectively, ensure the gas will be competitive.

Contracts should also contain provisions to protect the parties in the event of changes, the circumstances in which the contract is expected to operate, and to permit contractual adjustments in such circumstances. Examples of such provisions include renegotiation clauses, arbitration clauses, "market-out" clauses, and similar arrangements. Again, no specific or predetermined provision to permit contract adjustments is favored, allowing the contracting parties discretion to determine the approach most suitable to their import arrangement.

*Need for the natural gas.*

The need for the imported gas will be addressed in terms of the marketability of the proposed import. Need for a gas supply is intrinsically related to its anticipated marketability. Thus, if the imported gas is competitive in the proposed market area and, through its contract terms, will remain competitive throughout the contract period, then the rebuttable presumption exists that the gas is needed in that market. To the extent that there exists a specific objection on the grounds of need for the import, the focus should be on the overall energy requirements in the market that can be met competitively by domestic natural gas and other fuels.

National energy requirements are also a factor, particularly in assessing long-term import arrangements, as the energy security of the nation remains a policy consideration.

*Security of supply.*

The security of gas supply and its transportation to the U.S. border are important components of the public interest, especially those under long-term arrangements. An import will be considered secure if it does not lead to undue dependence on unreliable sources of supply. Thus, imports involving relatively larger volumes and longer time periods must demonstrate relatively greater reliability of supply than smaller scale imports for a shorter time period. . . .

Security of a proposed import supply can be demonstrated by reference to the historical reliability of the supplier to provide a dependable source of gas to the United States and other countries. Reference can be made to any gas reserves committed to the import arrangement for the term of the contract.

Attention will be given to the advantage provided to the nation by a reliable supply of imported natural gas, which adds to the diversity of energy sources and provides an added measure of energy security during any period of energy shortage or emergency.

In addition to these considerations, the Administrator will consider any international trade policy, foreign policy, and national security interests that may bear on an import authorization. In so considering these and other factors as may be appropriate, the Department of State will be consulted in accordance with Section 102(10) of the DOE Organization Act.[172]

Under the new guidelines for approving natural gas imports, "ERA will no longer perform a detailed, technical assessment of cost elements of a proposed import, but rather will exercise its discretion by examining an import arrangement as a whole, including all terms and conditions collectively."[173]

The market responsiveness of each transaction has become an additional, albeit, unwritten, criterion. Under the umbrella of the policy guidelines and implementing regulations, since 1985 ERA has taken a market-oriented approach that allows importers to obtain prior blanket approval for up to two years without the need to submit each transaction for authorization.[174]

This review contrasts with ERA decisions prior to the 1984 guidelines requiring the inclusion of specific clauses in import contracts.[175] Although volume, price, take-or-pay obligations, make-up provisions, and length of contract are still the written criteria to be considered in determining marketability, the presence or absence of a specific

172. *Id.* at 6,688 (1984).

173. Buckley & Grammer, *supra* note 3, at 32-33.

174. *Id.*

175. For example, pre-guideline approvals were given with express conditions: Vermont Gas Systems, Inc., 1 ERA (CCH) ¶ 70,534 (1981) (volume and price); Montana Power Company, 1 ERA (CCH) ¶ 70,542 (1981) (authorized price); and Transcontinental Gas Pipe Line Corp, 1 ERA (CCH) ¶ 70,540 (1982) (schedule of volumes, prices, and alternate transportation arrangements).

clause will not be determinative.[176] In addition to adopting a flexible approach for reviewing import applications, the ERA has looked to the market to determine whether contracts should be approved. For example, need will be presumed if the price is competitive, which in turn has been assumed when contracts were for deliveries to areas where imported natural gas had historically constituted a significant portion of supply.[177] Favorable consideration was also shown where the terms of a contract permitted adjustments for changed circumstances, e.g., by including renegotiation clauses, interruptible purchase clauses, arbitration clauses, and "market-out" provisions, even though changes under such clauses were to be reported to ERA.[178]

Moreover, while the ERA has stated that applicants should attach executed contracts showing the identity of the parties to the transaction, numerous blanket authorizations for spot sales have been granted for which no contracts were executed at the time of the approval.[179] Through this practice, if spot imports are made under an ERA blanket authorization, there may be up to ninety days before the import must be reported.[180] In this manner, short-term confidentiality may be assured for an interim period. A more thorough discussion of spot-market procedures is contained in the following section.

*C. Spot Market Blanket Authorizations*

Even though the majority of natural gas volumes imported from Canada move under long-term authorizations, in 1985 ERA began to experiment with short-term, pre-approved blanket authorizations. This approach was taken not long after the NEB announced its new pricing policy and contract renegotiations began in 1983-1984. According to the principal DOE report on this subject, ERA developed its own blanket approval procedure for short-term contract arrangements as an extension of its new policy guidelines because:

> The ERA determined that these short-term, spot market sales of gas are inherently competitive and thus do not require the same conditions of advance notice that are necessary for long-term authorizations, including pricing information and identification of purchasers and suppliers. . . .[181]

In October 1984, prior to the new Canadian pricing policy becoming effective, Transcontinental Gas Pipe Line was the first applicant to be authorized to import volumes from Canada for direct and inter-

176. Interview with Constance L. Buckley, *supra* note 164.
177. Northwest Pipeline Co., 1 ERA (CCH) ¶ 70,537 (1981) at 72,177.
178. El Paso Natural Gas Co., 1 ERA (CCH) ¶ 70,533 (1981) (rate renegotiation clause); Midwestern Gas Transmission Co., 1 ERA (CCH) ¶ 70,559 (1984) (interruptible purchase clause); and Transcontinental Gas Pipe Line Corp., 1 ERA (CCH) ¶ 70,573 (1984) (reduced take-or-pay obligations).
179. Interview with Constance L. Buckley, *supra* note 164.
180. Poco Petroleum, Inc., 1 ERA (CCH) ¶ 70,829 (1988).
181. U.S.-CANADA GAS TRADE REVIEW, *supra* note 2, at 26.

ruptible sales, beyond its previous authorizations for system supply.[182] Shortly thereafter, two other spot programs were authorized under implementation of the new guidelines.[183]

Blanket authorizations have since become increasingly popular. Their advantages include reduced time for regulatory approval, particularly when combined with: (1) the NEB's new policy of turning around spot market applications in three working days; and (2) the FERC's new rules on self implementing transportation.[184] With these expedited procedures, it is possible for a spot transaction to be "on line" in a matter of days, assuming, of course, that pipeline transportation is secured. A blanket authorization saves the expense of making multiple filings for the purpose of identifying each sales transaction, although these import approvals are strictly monitored through "after-the-fact reporting" conditions.[185]

The ERA has not attached burdensome terms and conditions to its approvals and has also refrained from holding time-consuming evidentiary hearings or oral presentations. For example, in the Transco/Sulpreto proceeding, intervenors had requested the inclusion of a condition that if they were no longer beneficiaries of Transco's direct sales of Sulpreto volumes, then the authorization for the import of such volumes would terminate.[186] In declining to attach this condition, the ERA stressed that its:

> [P]olicy . . . places a premium on the ability of commercial parties to craft import arrangements with a minimum of governmental obstacles and interference. . . . Under this policy, the government defers to the workings of the market for selling price, recognizing that buyers and sellers will optimize the benefits for the parties involved.[187]

Quarterly reports of spot volumes imported, parties to transactions, prices, and quantity of gas sold were the only conditions attached to the approval order.[188]

The two-year authorization is the only significant restriction on spot-market blanket authorizations. This limitation has not been much of an obstacle because ERA is routinely granting requests for reauthorization and extension of its early blanket approvals.[189]

Since the adoption of the ERA's guidelines, blanket authorizations have been issued with little procedural burden being placed upon the

182. Transcontinental Gas Pipeline Corp., 1 ERA (CCH) ¶ 70,573 (1984).
183. Cabot Energy Supply Corp., 1 ERA (CCH) ¶ 70,124 at 70,759-62 (1985); Northwest Alaskan Pipeline Co., 1 ERA (CCH) ¶ 70,585 (1985).
184. Interview with Constance L. Buckley, *supra* note 164.
185. Buckley & Grammer, *supra* note 3, at 33-34.
186. Transcontinental Gas Pipeline Corp, 1 ERA (CCH) ¶ 70,753, at 72,316.
187. *Id.* at 72,317-18.
188. *Id.* at 72,318.
189. *See, e.g.,* Access Energy Corp, 1 ERA (CCH) ¶ 70,835 (1989); CanadianOxy Marketing Inc., 1 ERA (CCH) ¶ 70,839 (1989).

applicant.[190] For example, the ERA approved a spot market proposal by Northwest Alaskan Pipeline Company in a proceeding in which an intervenor had requested a trial-type hearing.[191] In the *Northwest Alaskan Pipeline* proceeding, a number of intervenors expressed fears that the Northwest Alaskan spot program would compete unfairly with domestic suppliers. The ERA turned down the request for hearing and declined to condition its approval in order to prevent the spot sales from displacing long-term imports. In so doing, the ERA noted that competition between long-term supplies and spot supplies would force restructuring of markets along more competitive lines.[192] The ERA approved the *Northwest Alaskan Pipeline* proposal and simply attached what has now become a standard set of reporting requirements.[193] Blanket authorizations approved more recently include the same requirements.[194] Currently, 129 spot market proposals with a total volume of 23 TCF have been approved by the ERA since February 22, 1985, although only 558 BCF, less than one percent, has actually been marketed.[195] According to ERA statistics, in 1988, 1266.42 BCF of Canadian natural gas was imported into the U.S. and, of this, 331 BCF or 26 percent moved under blanket authorizations.[196] This compares with over 60 percent of domestic natural gas sales moving in the spot market for the same period.[197]

Despite the high degree of flexibility shown by the ERA for changing market conditions, most, but not all, applications are successful. For example, a request by the Kern River Pipeline project for blanket authority to import Canadian natural gas at Kingsgate and Huntingdon was withdrawn after the applicant was advised that because it intended to enter into long-term marketing commitments, ERA would require that the executed contracts be submitted.[198]

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190. St. Lawrence Gas Co., Inc., 1 ERA (CCH) ¶ 70,576 (1984); Northwest Natural Gas Co., 1 ERA (CCH) ¶ 70,577 (1984) (purchases from Canadian suppliers were to be on either a "reasonable efforts" or "best efforts" basis).

191. Northwest Alaskan Pipeline Co., 1 ERA (CCH) ¶ 70,585 (1985).

192. *Id.* at 72,368.

193. *Id.* at 72,370. The standard conditions now include: (1) written notification of date of first delivery; (2) quarterly reports on prices and volumes; (3) designation of purchasers, sellers and ultimate markets; and (4) all contract adjustments. *Id.*

194. *See, e.g.,* Gas Master's, Inc., 1 ERA (CCH) ¶ 70,832 (1988); Seagull Marketing Serv., Inc., 1 ERA (CCH) ¶ 70,833 (1988).

195. Telephone interview with John Glynn, Natural Gas Division, Office of Fuels Programs, Office of Fossil Energy, U.S. Department of Energy (March 6, 1989).

196. *Id.* The ERA prefers to use NEB statistics rather than those reported on FERC Form 15. *Id.*

197. Telephone interview with Constance L. Buckley, *supra* note 44.

198. Kern River Gas Supply Corp., ERA Docket No. 86-12-NG (June 18, 1987). The Kern River proposal involved the importation of 350,000 MCF/d to be sold or assigned to enhanced oil recovery (EOR) operations under 15-year contracts. In issuing a procedural order proposing to deny long-term blanket authorization, the ERA Administrator stated:

> [B]lanket authority to import up to a daily average of 350,000 MCF of Canadian gas per day for sale to California EOR producers over a 15-year period is inconsistent with the public interest.

*Id.* at 7.

D. Timetable for ERA and FERC Approvals

The time it takes to secure ERA and possibly FERC approval of an import of Canadian gas into the U.S. can run the gamut from a matter of days to many months, depending on the kind of transaction. Spot sales authorized under blanket authorizations by the ERA and utilizing self-implementing transportation programs can be "on line" in a matter of days.[199] Long-term sales, sales that require the construction of facilities, or sales that will need an individual authorization for transportation under Section 7(c) of the NGA, take a minimum of 4 to 5 months if done under delegation to the Office of Producer and Pipeline Regulation.[200] Significantly more time is required when the application is contested.[201] There has not been sufficient experience under the optional expedited procedures associated with open access pipelines pursuant to Order 500 to estimate the processing time required for these applications.[202] As with traditional 7(c) certificates, complex projects requiring review under the National Environmental Policy Act, and intervention by shippers or opposing parties can add substantial delay to the Order 500 process.[203]

The time necessary to secure FERC approval of a proposed import can vary substantially. If the purchaser can take advantage of an open access or self-implementing transportation program, no approval will be necessary.[204] An uncontested Section 7 proceeding, necessary when the transportation cannot be accomplished under the above expedited programs, will take about 90 days.[205] Contested proceedings add significantly to the time necessary to obtain FERC approval making them unsuited for spot market purposes.[206]

199. American Central Gas Marketing Co., 1 ERA (CCH) ¶ 70,834 (1989) (blanket authorizations for spot sales are being approved in approximately 60 days from the date the initial application is filed).

200. Telephone interview with Robert J. Szekely, Director, Division of Pipeline Certificates, Federal Energy Regulatory Commission (April 5, 1989).

201. *Id.*

202. *Id.* FERC has only issued two certificates under the optional, expedited procedures. *See* Wyoming-California Pipeline Company, 45 F.E.R.C. (CCH) ¶ 61,353 (1988) and Moraine Pipeline Co., 42 F.E.R.C. (CCH) ¶ 61,144 (1988).

203. *Id.*

204. Self-implementing transportation is authorized under Section 311(a) of the NGPA. 42 U.S.C. § 3371(a).

205. Interview with Constance L. Buckley, *supra* note 164.

206. *Id.*