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Report to the Chairman, Subcommittee on Oversight and Investigations, Committee on Energy and Commerce
House of Representatives

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CANADIAN POWER IMPORTS

A Growing Source of U.S. Supply

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Resources, Community, and
Economic Development Division

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April 30, 1986

The Honorable John D. Dingell
Chairman, Subcommittee on
Oversight and Investigations
Committee on Energy and Commerce
House of Representatives

Dear Mr. Chairman:

In accordance with your request, this report discusses the impacts of Canadian power imports on the United States. Specifically, the report examines the current import situation and future prospects, the affect of imports on electrical utility plans for meeting future power needs, and concerns being expressed about the growing use of imports.

At your request, we did not obtain agency comments, nor were any drafts circulated to the agencies. As arranged with your office, unless you publicly announce its contents earlier, we will make no further distribution of this report until 30 days from its publication date.

Sincerely yours,

J. Dexter Peach
Director

Executive Summary

U.S. reliance on Canadian power imports is growing. The amount of electricity imported from Canada has increased 16-fold since 1970. In 1984 U.S. utilities purchased over $1 billion worth of electricity from Canadian utilities. (See p. 8.)

The Chairman, Subcommittee on Oversight and Investigations, House Committee on Energy and Commerce, asked GAO to review current and future import levels and several specific issues associated with U.S. utilities' heavier reliance on imports as a source of power. GAO examined the current import situation and evaluated specific issues, including how imports are priced, the cost-effectiveness of imports versus building new power plants in the United States, the nation's increasing dependence on a foreign power source, technical reliability concerns associated with importing larger quantities of Canadian electricity, and the use of imports instead of domestic power surpluses. (See pp. 8 and 9.)

Background

For many years the flow of power between the United States and Canada was relatively balanced. However, since 1970 U.S. utilities have purchased increasing quantities of Canadian electricity. For the most part, imported electricity has been used to displace the output of U.S. utilities' existing oil- and gas-fired power plants. Only to a limited degree have U.S. utilities relied on imports in lieu of building new power plants in this country.

By using imports to displace their own existing power generation, U.S. utilities have saved hundreds of millions of dollars. These savings result because Canada can offer electricity at a price lower than that at which the United States can produce it, primarily because of Canada's large hydroelectric resource base. Hydropower, which is produced at dams using falling water to generate electricity, is generally less expensive than other forms of power generation because of its lower construction costs and lack of fuel costs. (See p. 15.)

Results in Brief

Under existing contractual arrangements, the amount of Canadian electricity imported by U.S. utilities is expected to continue increasing through 1995. If ongoing contract negotiations between U.S. and Canadian utilities are successful, the use of imports will continue to grow beyond the year 2000. It appears that in the future, imports will be used more extensively as a substitute for building new power plants in the United States.

With respect to specific issues associated with the changing import situation, GAO found that the basis for pricing imported power differed between the New England and Midwest regions; however, the price paid for imported power in both regions appears to result in cost advantages to domestic utilities and consumers. With respect to dependency, GAO found that current purchases of Canadian power do not exceed levels considered acceptable by utility and regulatory officials. Concerning the issue of technical reliability and the potential for transmitting surplus domestic power between regions, GAO found that industry groups and utilities have been examining these matters in an effort to resolve the concerns. (See p. 24.)

Principal Findings

Net U.S. imports of Canadian electricity have grown from 2.4 million megawatt hours (MWH) in 1970 to 39.5 million MWH in 1984. In regions of the country bordering Canada, the percentage of import use is higher than that for the nation as a whole. In New England, for example, 5.9 million MWH, or 6.4 percent, of the electricity consumed in 1984 was imported from Canada. This compares with 1.6 percent nationally. (See pp. 13 to 15.)

Current sales agreements between U.S. and Canadian utilities call for this trend to continue, with 44.7 million MWH scheduled for delivery in 1990. According to utility officials, because of the uncertainties associated with building power plants domestically and the willingness of Canadian utilities to build generating capacity for export, imports from Canada will be used increasingly as an alternative to building power plants in the United States. (See p. 19.)

Pricing

Under the power sales contracts GAO reviewed, the price charged for imported power is generally set as a percentage (frequently 80 to 95 percent) of the purchasing utility's cost for alternative domestic sources of electricity. This appears to result in a cost advantage for U.S. utilities whether the imported electricity is used to displace the electricity from existing power plants or in lieu of building new power plants. Analyses we reviewed comparing the cost of imports to the cost of building new power plants in both New England and the Midwest give imports a cost advantage under current pricing arrangements. (See pp. 24 to 27.)

Dependency

Utility and regulatory officials GAO spoke with expressed no concern over the use of imports as long as domestic power plants are available to back them up. On the issue of using imports instead of building domestic generating capacity, utility and regulatory officials indicated that a reasonable level of imports is generally 15 to 20 percent of the purchasing utility's generating requirements. GAO found in the two geographical areas where imports are used most heavily that the 15- to 20-percent level will not be exceeded based on existing contracts and ongoing negotiations. (See pp. 27 to 30.)

Technical Reliability

GAO found that the technical reliability issues associated with imports focus on the reliability of the Hydro-Quebec power system and the potential impacts on U.S. power systems if the Quebec system suffers a serious power outage. The New England Power Pool is studying ways to improve the overall reliability of the transmission ties with Hydro-Quebec, and in conjunction with Hydro-Quebec, is taking steps to improve the reliability of the power exported by Hydro-Quebec and associated transmission facilities. (See pp. 30 to 32.)

Domestic Surpluses

The central issue associated with the use of Canadian electricity when selected utilities in the Midwest have surplus power available is the ability to move Midwest power to New England. According to a North American Electric Reliability Council (NERC) study, the transmission systems between the two regions are operating at full capacity on a daily basis. To move significant amounts of additional power, new transmission lines will be needed. NERC has identified regulatory, legislative, environmental, and financial impediments to constructing new lines. According to NERC, each impediment has the potential to delay transmission line completion to the extent that any economic benefits may disappear. NERC is studying the issue further. (See pp. 32 and 33.)

Observations

On the basis of the current import situation and GAO's evaluation of issues raised concerning this situation, GAO believes that electricity imports provide a cost-effective source of electricity. Further, it appears that the attractiveness of imports will continue, given the potential hydropower resources in Canada. It is unclear, however, what utilities will do in the future relative to constructing new domestic power plants as they approach the 15- to 20-percent reliance level. The decision to rely on imports beyond the 15- to 20-percent level, in GAO's view, will depend on (1) utilities' analyses of the uncertainties associated with building domestic power plants and (2) the extent to which current limitations to moving power between regions have been resolved.

Recommendations

GAO is making no recommendations.

Agency Comments

GAO did not obtain agency comments on this report.

Contents

Figures

Abbreviations

AC	alternating current
AFUDC	Allowance for Funds Used During Construction
APPA	American Public Power Association
DC	direct current
DRI	Data Resources Incorporated
DOE	Department of Energy
ECAR	East Central Area Reliability Coordinating Agreement
EEI	Edison Electric Institute
EIA	Energy Information Administration
EIS	environmental impact statement
EPA	Environmental Protection Agency
GAO	General Accounting Office
kwh	kilowatt hour
MAAC	Mid-Atlantic Area Council
MW	megawatt
MWH	megawatt hour
NARUC	National Association of Regulatory Utility Commissioners
NEB	Canadian National Energy Board
NEPA	National Environmental Policy Act of 1969
NEPOOL	New England Power Pool
NERC	National Electric Reliability Council

Introduction

Canadian imports are a small but increasing source of power for meeting U.S. electricity needs. During 1984 the United States imported 1.6 percent of its national electricity supply from Canada. Net Canadian electricity imports increased more than 16-fold between 1970 and 1984, from 2,386,000 megawatt hours (MWH) valued at $22.5 million to 39,554,905 MWH valued at $1.05 billion.[1] This growth primarily has occurred as utilities have increasingly used imported electricity to displace the higher cost electricity that could be generated from their existing oil- , gas- , and coal-fired generating facilities.

Although Canadian imports provide a small percentage of our national supply, they contribute a much greater share of the electricity used in some states near the Canadian border, particularly in the northeastern United States. New York, for example, used Canadian electricity to meet about 17 percent of its electrical needs in 1984. The six New England states used Canadian electricity to meet about 6 percent of their 1984 electrical needs.

In order to import electricity from Canada, transmission lines crossing the U.S./Canadian international border must be available. Such transmission lines are required to be licensed by the federal government. The license, called a Presidential Permit, is issued by the Department of Energy (DOE). The licensing process ensures that the transmission lines do not have adverse environmental or power system reliability effects on the territory of the United States.

The increasing use of imports has generated discussion among federal and state officials, and utility executives. Although there is little disagreement over importing lower cost electricity to displace the higher cost electricity that could be produced from U.S. generating facilities, questions have been raised about whether greater reliance on Canadian generating capacity to meet future demand instead of building new power plants in the United States is in the best interests of consumers, the utilities, and the nation.

Objectives, Scope, and Methodology

The Chairman, Subcommittee on Oversight and Investigations, House Committee on Energy and Commerce, requested that we evaluate current and future import levels and several specific issues associated with U.S. utilities' heavier reliance on imports as a source of power. The

[1] A megawatt hour is a unit of electrical energy equal to 1 megawatt (MW) of power applied for 1 hour. See the glossary for definitions of this and other terms used in this report.

Chairman raised specific issues related to this situation, including the desirability of increased U.S. dependence on foreign power imports, the method used to price imports, the cost of using imported power in relation to the cost of building new domestic power plants, the impact of imports on domestic utility construction programs, and the use of imported power instead of domestic power surpluses.

The Chairman also asked us to review DOE's activities related to Canadian electricity imports, and in particular, DOE's process for granting the permits required to construct transmission lines across the U.S. border.

As agreed with the Chairman's office, our objectives were to determine the current situation with respect to Canadian electricity imports, identify DOE activities related to electricity imports, and evaluate issues being raised concerning this situation.

As agreed, we limited the scope of our review to the three U.S. geographical areas that import the majority of the electricity—the state of New York, the New England region, and the Midwest region, including the states of Michigan, Minnesota, and Wisconsin. Our review also included the Canadian provinces of Manitoba, Ontario, Quebec, and New Brunswick.

The Pacific Northwest—including the province of British Columbia and the states of Washington, Oregon, Idaho, and Montana—was specifically excluded from this review because the utilities in this region are mutually dependent on the Columbia River system for hydropower. The joint use of a single resource and a 1961 treaty between the United States and Canada have created a situation that is unique to this region.[2] We anticipate reviewing the issues associated with Canadian power imports in the Pacific Northwest in a subsequent report.

To determine the current U.S. import situation, including the issues associated with increased imports, we examined existing and proposed import contracts, existing utility generating capacity, utility load and capacity forecasts, and recent publications related to the topic of Canadian electricity imports. We spoke with numerous utilities and regulatory entities in both countries, including the Canadian National Energy Board (NEB), provincial governments, and state regulatory commissions.

[2] The Columbia Treaty is a plan developed by the Canadian and U.S. governments to develop the hydroelectric potential of the Columbia River to the advantage of both countries.

We also spoke with representatives of the American Public Power Association (APPA), the Edison Electric Institute (EEI), the National Association of Regulatory Utility Commissioners (NARUC), the North American Electric Reliability Council (NERC), and individual regional reliability councils and power pools. A complete list of the parties we contacted is in appendix I.

We interviewed national, provincial, and utility officials in Canada to determine their policies, current plans, and future prospects for electricity exports to New York, New England, and the Midwest. We examined Canadian procedures and criteria for approving electricity exports. We also obtained demand forecasts and generating capacity expansion plans for both U.S. and Canadian utilities. Further, we discussed with utility officials selected ongoing and proposed contracts for electricity sales, and reviewed the conditions under which Canadian utilities and regulators would consider additional exports. We also obtained statistical information on electricity trade and transmission interconnections as well as other documents and reports prepared by Canadian organizations relevant to our assignment objectives.

To determine the cost of using imported power in relation to the cost of building new domestic power plants, we performed a limited economic analysis of these alternatives under various scenarios. This analysis is described in detail in appendix II.

We also discussed with state and utility officials the advantages and disadvantages of increasing the amount of electricity imports and potential changes in the type of electricity imported and its use.

To determine DOE's activities in the electricity import area, we reviewed DOE programs related to imports, including the process for issuing a Presidential Permit for transmission interconnections. We also identified DOE staffing levels devoted to the permit process and reviewed the budget for this effort. At the request of the Chairman's office, we briefed his staff in April 1985 on the preliminary information we had obtained. A discussion of DOE activities related to the Presidential Permit process is contained in appendix III.

We did not obtain agency comments on this report. We did, however, discuss the contents of appendix III with agency officials. Their comments are incorporated where appropriate. Except as noted above, we performed our work in accordance with generally accepted government auditing standards. Our audit work was conducted between March and December 1985.

Canadian Electricity Import Levels Are Growing

The use of imports to meet U.S. electricity requirements is increasing in each of the three regions we reviewed. In 1985 these three regions were projected to import a total of 36.8 million MWH of electricity from Canada. Under current signed contracts, imports to these regions are projected to peak in 1990, with 44.7 million MWH anticipated for delivery.

Industry projections of future demand in the Midwest and New England indicate the need for additional power resources in the 1990's. Utility officials stated that because of the lower cost and availability of Canadian electricity, contracting for Canadian generating capacity will continue to be an attractive alternative to building new power plants to meet U.S. electricity needs. To a limited degree imports have already delayed the need to construct new domestic power plants. However, according to utility officials, imports have not affected utility decisions related to power plants under construction or other power resource development, such as cogeneration and energy conservation.[1]

Canadian government and provincial utility officials support the expansion of power exports to the United States. In negotiations for future contracts, Canadian and U.S. utilities are proposing longer term agreements and firmer supply assurances than are contained in most existing contracts. However, constraints do exist to future expansion increases in Canadian electricity imports. These include transmission limitations and marketing uncertainties.

Imports Are a Growing Supply Source

From 1959 to 1970 the flow of electricity between the United States and Canada was fairly balanced. However, as figure 2.1 illustrates, in 1970 the difference in amounts of U.S. imports and exports began to widen. By 1984 U.S. utilities imported almost 17 times as much electricity as they exported. Several factors have contributed to the dramatic rise in the import level—primarily, a widening difference in electricity production costs between the two countries and the overbuilding of Canadian generating capacity in the 1970's.

[1] Cogeneration, generally, is the dual use of steam or heat for an industrial, commercial, or manufacturing plant or process, and for electricity generation.

Figure 2.1: Electricity Trade Between the United States and Canada

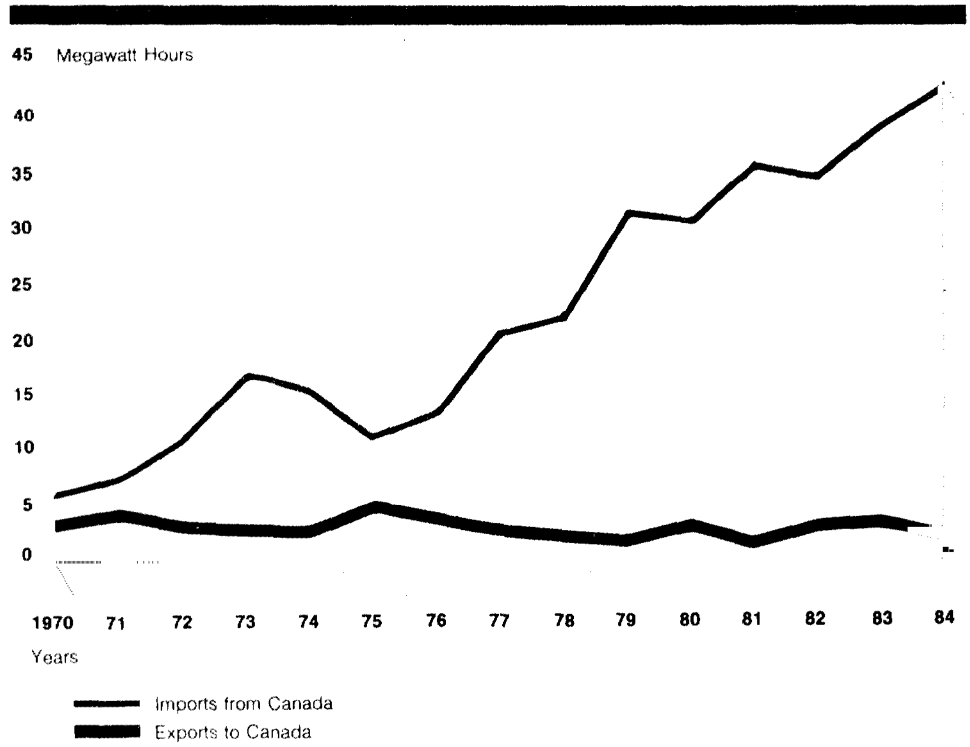


Table 2.1 shows how the value of electricity trade has changed from a trade surplus of $1.7 million by U.S. utilities in 1965 to a trade deficit of $1.05 billion in 1984, the latest year for which figures were available.

Table 2.1: Electricity Trade Between the United States and Canada, 1965-84

Figures in thousands

Year	U.S. imports from Canada (MWH)	U.S. exports to Canada (MWH)	Trade surplus/ deficit
1965	3,570	3,575	$ 1,704
1966	4,310	3,057	(5,540)
1967	4,066	4,142	5,744
1968	3,646	4,129	2,529
1969	4,688	3,333	(9,474)
1970	5,631	3,245	(22,460)
1971	6,985	3,378	(37,826)
1972	10,379	2,381	(62,206)
1973	16,879	2,249	(108,633)
1974	15,399	2,441	(172,191)
1975	11,375	4,174	(100,285)
1976	12,804	3,590	(169,541)
1977	19,957	2,690	(382,176)
1978	21,602	2,092	(418,146)
1979	31,378	1,792	(630,083)
1980	30,180	2,940	(675,997)
1981	35,372	1,497	(949,308)
1982	34,220	2,849	(892,497)
1983	38,830	3,179	(1,008,428)
1984	42,034	2,479	(1,045,904)

Sources: Figures for U.S. imports from Canada and U.S. exports to Canada (except 1984 figures): NEB. Figures for trade surplus/deficit (except 1984 figure): NEB (converted to U.S. dollars by GAO). 1984 figures: DOE.

In 1984 Canadian electricity imports represented 1.6 percent of the total electricity consumed in the United States. As table 2.2 illustrates, some regions relied more heavily on imports than others.

Table 2.2: Selected Regional Electricity Imports From Canada, 1984

Figures in megawatt hours

Region	Electricity requirements	Electricity imports	Net imports as a percentage of electricity use
Lower Michigan	71,686,000	555,910	0.8%
Upper Midwest	105,278,000	5,734,848	5.4%
New England	92,195,000	5,918,431	6.4%
New York	124,338,000	20,917,402	16.8%

Source: DOE, Electricity Transactions Across International Borders - 1984.

Canada's Lower Cost Resources Support Increased Import Levels

Canadian power imports are expected to continue increasing in the future. Table 2.3 shows forecasted Canadian electricity exports to the United States from selected provinces for the years 1985 through 2000. The forecasts include only those contracts that have been signed and for which all regulatory approvals have been obtained. The amount of electricity exported to the United States will be higher than forecasted if current or future negotiations result in new contracts.

Table 2.3: Forecasted Canadian Electricity Exports for Selected Provinces (MWH)

Figures in thousands

	1985	1986	1990	1995	2000
New Brunswick	6,889	7,664	6,051	2,692	1,544
Quebec	13,362	19,179	22,072	17,131	15,884
Ontario	9,800	9,700	11,600	10,800	5,200
Manitoba	6,727	6,442	5,009	10,025	11,447
Total	**36,778**	**42,985**	**44,732**	**40,648**	**34,075**

Source: Energy, Mines and Resources Canada.

Canada's vast hydroelectric resources are the predominant means of generating electricity in that country and are the key to its ability to maintain the relatively low electricity prices that make imports attractive to U.S. utilities. In addition to their developed hydroelectric resources, both Manitoba and Quebec have large undeveloped hydroelectric resources that could be used for export to the United States. According to Canadian utility officials, Manitoba and Quebec have 9,100 MW and 20,000 MW, respectively, of economically attractive hydroelectric potential.

Hydroelectric power facilities, overall, cost less to build and have no associated fuel costs as compared with other types of generating facilities. Therefore, hydroelectric power provides a significant cost advantage over power produced in the United States from other types of power plants. According to an Energy Information Administration (EIA) analysis,[2] nuclear plant construction costs are almost six times those of hydroelectric plants; coal plant construction costs are four to five times as expensive. Power production costs (excluding plant construction) are estimated by EIA to be 11 times more for coal and five times more for nuclear than for hydropower.

As illustrated in table 2.4, nearly 60 percent of Canada's capacity in the provinces we visited is supplied through hydropower, with two of the

[2] EIA, U.S.-Canadian Electricity Trade (Nov. 1982).

four provinces relying almost exclusively on hydropower for their electricity requirements.

Table 2.4: Canadian Electricity Supply for Selected Provinces, 1984

Figures in Megawatts[a]

	Nuclear	Fossil	Hydro	Total
New Brunswick	680	1,904	901	3,485
Quebec	951	1,119	24,761	26,831
Ontario	7,956	13,670	7,131	28,757
Manitoba	•	501	3,641	4,142
Total	**9,587**	**17,194**	**36,434**	**63,215**

[a]A megawatt is a unit of electrical power equal to 1 million watts.
Source: Energy, Mines and Resources Canada.

Canadian utilities, with the support of the Canadian national and provincial governments, have expressed a willingness to develop their electricity resources for export in advance of Canadian need. All of the Canadian officials we interviewed indicated exports are likely to increase if appropriate contract terms (e.g., price, contract length, assured purchase) can be negotiated.

Import Contracts Vary

Agreements between U.S. and Canadian utilities for purchasing electricity differ. One type of agreement allows U.S. utilities to meet their customers' demand with Canadian electricity rather than generating that same amount of electricity with their own existing generating facilities. These types of purchases are generally referred to as displacement purchases and consist of economy and surplus energy contracts. Under another type of agreement, U.S. utilities purchase access to Canadian electricity generating capacity and/or the associated energy. These agreements are referred to as firm power or firm energy purchases. Utilities can use firm power purchases in lieu of building new power plants of their own.[3]

In the 1970's utilities began to sign increasing numbers of economy and surplus energy contracts. Under these contracts, U.S. utilities take delivery of Canadian energy when it is available and less expensive than their domestically generated electricity. Generally, economy transactions are only hours in duration while surplus sales may cover several

[3] In addition to the basic agreements to purchase electricity, U.S. and Canadian utilities have established interconnection agreements, which may involve purchases of electricity, but which primarily provide for using transmission line interconnections for emergencies and improving the operating efficiency of both the U.S. and Canadian utilities' power systems.

years. Although these contracts frequently carry a target level of electricity to be delivered, delivery of a set amount of electricity is not guaranteed. Most of the electricity currently imported by U.S. utilities from Canada is purchased under these types of contracts.

Economy energy is usually priced under a "split savings" formula, which means that the price of electricity is established between the Canadian utility's actual production costs for the electricity and the higher, "avoided" production costs for the U.S. utility.[4] The pricing mechanism used in surplus energy sales contracts varies from fixed prices per kilowatt hour (kwh), to prices dependent upon the avoided cost of the buyer, incremental costs of the seller, or both.[5] The pricing mechanism that has been used in several existing contracts is pricing Canadian imports at a specified percentage of the purchasing utilities' cost of production. By providing U.S. utilities with electricity at a lower price than their cost to produce it domestically, economy and surplus energy contracts have saved U.S. consumers hundreds of millions of dollars.

In addition to economy and surplus energy sales contracts, a limited number of firm power and firm energy contracts have been negotiated between U.S and Canadian utilities. A firm power contract requires the Canadian utility to make capacity available to the U.S. utility on demand during the contract period. Therefore, U.S. utilities can rely on the capacity purchased almost as they would generating capacity within their own power systems. Currently, firm power contracts provide 2.9 percent of the New England region's winter capacity requirements. Similarly, Northern States Power, a midwestern utility, currently obtains 8 percent of its summer capacity requirements from firm power contracts with a Canadian utility.

A firm energy contract provides for a specific amount of energy to be delivered over an agreed-to period of time (as opposed to providing that a certain amount of capacity will be available on demand). Our review identified only one firm energy contract. This contract covers the purchase of firm energy by the New England Power Pool (NEPOOL) from Hydro-Quebec, a Canadian utility.

[4] Avoided costs are the costs a utility would otherwise incur to generate power if it did not purchase electricity from another source.

[5] A kilowatt hour is a basic unit of electrical energy equal to 1 kilowatt of power for 1 hour. Incremental cost is the increase in the cost of generating or transmitting electricity above the base amounts.

The majority of the firm power contracts we identified are for the delivery of capacity on a seasonal basis. Under these contracts, there is generally a demand charge plus an energy charge.[6] The demand charge is a fixed amount; the energy charge is set between the production costs of the seller and the purchaser and varies over time.

There are seven contracts calling for year-round firm power or energy deliveries from Canada to U.S. utilities. These agreements, all of which have been signed since 1981, reflect the increasing use of imports to meet U.S. capacity needs in lieu of building new power plants, as opposed to importing economy or surplus electricity to displace higher cost domestic generation. These are

- the four Pt. Lepreau unit participation agreements between the New Brunswick provincial utility and Massachusetts Municipal Wholesale Electric Company, Boston Edison Company, Eastern Maine Executive Cooperative, Inc., and Commonwealth Electric Company, for a total of 230 MW of capacity and associated energy;
- the Vermont/Hydro-Quebec Higate contract for 150 MW of capacity and associated energy;
- the Northern States Power Company/Manitoba Hydro contract for 500 MW of capacity and associated energy; and
- the NEPOOL/Hydro-Quebec Phase II firm energy agreement for 700 million MWH over a 10-year period.[7]

Under the Pt. Lepreau agreements, the U.S. utilities have contracted for electricity produced by the Pt. Lepreau nuclear power plant in New Brunswick. With respect to pricing, the Canadian and U.S. utilities share the plant's costs during the contract period, even if the plant is not operating. The New Brunswick utility retains ownership of the power plant and at the end of the contract period can use the plant's output to meet provincial needs.

The price of imported electricity in the three remaining contracts is a percentage of the cost of alternative power available to the purchasing utility. The Northern States Power contract establishes the rate at 80 percent of the costs associated with one of Northern State's coal-fired

[6] The demand charge is that portion of the charge for electrical service that is based on the electrical capacity needed. The energy charge is that portion of the charge for electrical service that is based on the electric energy actually consumed.

[7] NEPOOL, using a computer model, has valued the firm energy to be delivered under the Phase II contract at 1,500 MW of capacity.

plants. The NEPOOL/Hydro-Quebec Phase II contract is indexed to NEPOOL's fossil fuel costs. During the first 5 years of the Vermont contract, the price is set in the contract; for the last 5 years, it is tied to NEPOOL's fossil fuel costs, plus a demand charge.

Capacity Purchases Delay the Need to Construct Domestic Power Plants

In the Midwest and New England, we found that utilities are delaying the need to build new power plants because of their contracts with Canada. However, according to utility and state regulatory officials, Canadian imports have not affected existing power plant construction programs. According to utility officials, because of financial and other uncertainties associated with building power plants in the United States, the utilities' desire to increase the types of resources used, and the willingness of Canadian utilities to build generating capacity for export, imports from Canada increasingly will be used as an alternative to building domestic generation. However, transmission constraints and uncertainties in Canadian utilities' ability to market power in the future may limit the potential growth in imports.

Imports Contribute to Meeting Capacity Needs

Through 1985, imported Canadian electricity has, for the most part, been purchased to displace more costly electricity generation from domestic power plants. Nevertheless, we found that to a limited degree, Canadian imports are also currently being used to meet capacity requirements of U.S. utilities. On the basis of utility demand and capacity forecasts and discussions with utility officials, it appears that firm power and energy purchases will provide a greater contribution to meeting domestic utility capacity needs into the 1990's.

As mentioned previously, utilities in New England and the Midwest currently meet a limited amount of their capacity needs on a seasonal basis through imported power. This situation has resulted from U.S. and Canadian utilities taking advantage of differing seasonal power needs. Canada is a winter-peaking region, while in most parts of the United States, peak demand occurs in the summer. As a result, domestic utilities have contracted to use Canadian capacity, which is in excess of Canada's summer needs, to meet their own summer peaks. Using Canadian capacity is less expensive than developing resources in the United States that would be used only seasonally. It also allows Canadian utilities to more efficiently use their generating facilities.

Under the firm power and firm energy contracts signed since 1981, Canadian capacity will be used more frequently in future years to meet the year-round capacity needs of some U.S. utilities. This is evidenced by demand and capacity forecasts for utilities in the New England and midwestern states. These forecasts show that for some period of time between 1989 and 1994, the domestic capacity available will not be sufficient to meet reserve margin levels considered acceptable for these utilities' power systems. However, when Canadian firm power and firm energy purchases already contacted for are included as capacity in the forecasts, acceptable reserve margins will be met. In contrast, New York utilities' projections show domestic capacity at levels adequate to meet capacity requirements through the year 2000.

According to New England and Midwest utility officials, their utilities have examined and continue to consider a variety of options for meeting future capacity needs. Options include energy conservation programs, cogeneration, coal plant construction, and Canadian imports. In the utility resource planning process, imports are viewed favorably as a future resource. More detailed contract information for the Northern States Power Company and NEPOOL follows.

Northern States Power

The only midwestern utility with a year-round firm power import contract is Northern States Power Company in Minnesota. According to its January 1985 estimated demand and generating capability data, Northern States Power currently obtains about 8.1 percent of its summer capacity requirements but none of its winter capacity requirements under a 13-year (1980-93), 500-MW contract with Manitoba Hydro, a Canadian utility. In 1984 the two utilities negotiated a new 12-year contract that begins when the current agreement expires. The new contract provides for the delivery of 500 MW of capacity year-round. In 1994, the last year included in demand and capacity forecasts prepared by Northern States Power, the 500-MW purchase under the 1984 contract represents 6.7 percent of the utility's adjusted net capability in the winter and 6.9 percent in the summer.

NEPOOL

Canadian contracts currently provide 2.6 percent of NEPOOL's winter capacity and 2.9 percent of its summer capacity. NEPOOL's 1985 demand and capacity forecast for the period 1985-2001 shows that these percentages peak at 7.8 percent and 8.2 percent, respectively, in 1992 and then decline gradually as existing contracts expire. NEPOOL forecasts indicate a need for additional resources in 1994; however, without the contribution of imports, additional resources would be needed in 1991 to meet its capacity requirements.

Imports Delay Decisions to Build New Power Plants

In the regions we examined, utility and state regulatory officials told us that imports were being used as a substitute for building new power plants but not as a substitute for other types of power resources, including conservation, cogeneration, load management, and renewable resources. These officials also told us that the availability of Canadian imports had not affected utility decisions related to power plants under construction.

According to utility and state regulatory officials, Canadian imports are viewed as an alternative to building new power plants (generally coal-fired units) because of the financial and other uncertainties associated with domestic power plant construction. Most utilities we spoke with believe that Canadian imports can provide a reliable source of capacity at a lower cost than U.S. utilities could provide by building additional power plants.

We noted that, excluding Canadian imports, Northern States Power would be unable to meet its capacity requirements with available domestic resources during the entire period covered by its 1985 forecast. Northern States officials agreed and indicated that its two Canadian import contracts have allowed Northern States to avoid building a coal generating plant to meet its capacity requirements and reliably meet customer demand. The 25-year period covered by the contracts approximates the 32-year useful life of a coal plant.

According to Northern States officials, the company will need to begin constructing one or two more coal plants within the next 2 years to meet a projected 1,000-MW capacity deficit in 1999. However, if current negotiations between Manitoba Hydro and a group of midwestern utilities, including Northern States, are successful, Northern States would be able to delay the construction of the coal plants.

NEPOOL officials stated that its Phase II contract with Hydro-Quebec will contribute to meeting capacity needs in the 1990's, and in doing so will defer the construction of domestic power plants. In its application for approval of the transmission facilities associated with this contract by the Massachusetts Energy Facilities Siting Council, NEPOOL stated that one of the benefits of its Hydro-Quebec contract is that it will defer the construction of new, and as yet unplanned, generating units in New England that would otherwise be needed in the latter half of the 1990's.

Deferring domestic power plant construction in New England has caused concern. One utility company president has said that if New England utilities defer decisions about creating domestic supplies because of short-term cost advantages, they may find that domestic generating plants are more expensive to build. In addition, the governor of New Hampshire told us that utilities are avoiding commitments to invest in new generating units as a "least risk strategy" to avoid involvement in the process of obtaining permits for siting facilities.

Although Canadian imports will delay the construction of new domestic power plants, utility officials and state regulators told us that the cancellation or deferral of power plants already under construction has been the result of low growth in the demand for electricity, financial problems, and regulatory problems, rather than the availability of electricity from Canada.

We discussed the events surrounding the cancellation or deferral of two nuclear power units under construction in the regions we visited with utility officials and state regulators. These discussions indicated that the availability of Canadian imports was not a factor in utility decisions to cancel or defer construction of these units. A summary of information concerning these units follows.

The Midland nuclear power plant in Michigan being built by Consumers Power, Inc., was cancelled in 1985. At that time, Consumers officials reportedly attributed the action to financing problems. Our interviews with company officials confirmed this. According to the vice chairman of the board, Consumers was forced to cancel the Midland plant when it was unable to finance the $1.0 to $1.5 billion needed to complete the plant. According to Consumers officials, the financial difficulties were caused, in part, by the state utility regulatory commission, which was unwilling to allow Consumers to recover an adequate part of the project's costs through its power rates to avoid bankruptcy.

Because of its financial situation, Consumers officials believe it will be unable to develop the new resources needed to meet projected demand in the 1990's. To the extent possible, Consumers will use its oil- and gas-fired power plants to meet demand.

In 1984 and 1985 the completion of the two Seabrook nuclear units being built by Public Service of New Hampshire was in doubt, not because Canadian power was available but primarily because of financing difficulties, according to New Hampshire Utility Commission documents. Subsequently, Seabrook Unit 2 was cancelled, and the construction management and financing arrangements for Unit 1 were reorganized. Unit 1 is currently under active construction and is scheduled for commercial operation in 1987.

Potential Limitations on Canadian Electricity Imports

Marketing uncertainties and technical constraints may limit the potential growth of Canadian imports. According to Canadian officials, Canadian provincial utilities have been using generating capacity that is in excess of their needs to serve the export market, but the excess is decreasing. Provincial utilities will need to build new generating facilities to serve and expand the export market beyond existing contractual arrangements. Provincial officials are concerned that contract negotiations with U.S. utilities may not be completed early enough to allow the lead time necessary for them to develop their resources to meet U.S. utility needs.

According to Ontario Hydro officials, transmission constraints within both Ontario and the U.S. may limit expansion of electricity exports. Within Ontario, transmission bottlenecks are being addressed. Within the U.S., the eastern U.S. transmission system is heavily loaded and thus will require new transmission capability to handle additional Canadian imports.

Analysis of Issues Associated With Canadian Electricity Imports

As the quantity of electricity imported from Canada has grown, a former Secretary of Energy and others, including utility and regulatory officials, have expressed concern about whether continued growth in electricity imports is in the best interest of the domestic utility industry. Specific areas of concern include basing the price of Canadian electricity on the costs of providing electricity from domestic oil-fired generating plants, increasing the nation's dependence on a foreign energy source, uncertainty about the technical reliability of the Canadian power system, and importing power at a time when power surpluses exist in some regions of the country.

We discussed these issues with DOE, utility, and regulatory officials. We found that the basis for pricing imported power differed between New England and the Midwest; however, the price paid for imported power in both regions appears to result in cost advantages to domestic utilities and consumers since the price is generally set below the cost to produce electricity domestically. Thus, we believe Canadian imports in these regions provide a cost-effective source of electricity. With respect to dependency, we found that current purchases of Canadian electricity generating capacity do not exceed levels considered acceptable by utility officials. Concerning the issues of technical reliability and the potential for transmitting surplus domestic power between regions, we found that industry groups have been examining these matters in an effort to resolve the concerns.

Imports Provide Cost Advantages

Concern that the price of imports is tied to the price of electricity produced by oil-fired generating plants has raised questions about the economic soundness of imports when compared to building new power plants in the United States. To address this issue, we reviewed the pricing provisions of recently signed contracts between Canada and utilities in the Midwest and New England. In addition, we reviewed two utility analyses of the costs of purchasing Canadian electricity compared to the costs of domestic alternatives for producing electricity. We also performed a limited economic analysis comparing the cost of imports under various scenarios to the cost of constructing a new coal plant.

Under the major contracts we reviewed, with limited exception, the price of imported electricity is based totally or in part on the price of electricity produced by generating units in the purchasing utilities' own system. In New England the price charged for imports is a percentage of

NEPOOL's average fossil fuel costs.[1] The fossil fuel calculation includes both oil- and coal-fired power plants. None of the contracts indexes the price of imports exclusively to oil-fired plants. The contract between Manitoba Hydro and Northern States Power sets the price at 80 percent of the cost of power to be produced by a coal plant owned in part by Northern States.

By indexing the price of imports to a percentage of domestic generating costs, U.S. utilities assure themselves of cost savings when using imports for displacement. According to NEPOOL, New England consumers are projected to save nearly $1.3 billion over the life of the existing surplus purchase agreement between NEPOOL and Hydro-Quebec (the Phase I contract). This estimate is net of the construction costs for transmission facilities required to deliver the energy.

The results of two utility analyses of the cost of Canadian electricity compared to domestic alternative sources of electricity supply showed that purchases of Canadian electricity were less costly. In October 1984, eight Minnesota and Wisconsin utilities negotiating with Manitoba Hydro for power published their feasibility evaluation of the proposed power transaction. As a part of this evaluation, each U.S. utility performed an economic analysis. The analyses compared the cost of the hydropower from Manitoba to coal-fired generation. The analyses used a coal alternative because this is the power supply source the Manitoba contract would replace.

The evaluation concluded that the hydropower option is 25- to 28-percent less expensive than the coal option. This conclusion is based on a 32-year contract for the hydropower, which the utilities assumed would be the useful life span of a coal-fired plant. A shorter contract would lower the value of the hydropower option to the U.S. utilities. How much the value would be lowered was not quantified in the evaluation.

In its application to the Massachusetts Energy Facilities Siting Council for a license to construct the transmission facilities needed to import

[1] Under the NEPOOL/Hydro-Quebec Phase I surplus purchase agreement and the Vermont Hydro-Quebec Higate contracts, the index is 80 percent of NEPOOL'S fossil fuel costs. Under the Phase II contract, the 80-percent figure is used for the first 5 years of the contract. For the remaining 5 years, a 95-percent index is used. The increase was negotiated to reflect the increased value of the energy to New England during the latter half of the contract period. In addition, it is anticipated that Hydro-Quebec will have to build new generating facilities to meet its obligations during the last 5 years. The increase, therefore, also recognizes the increased risk associated with the added construction.

firm energy under its Phase II contract with Hydro-Quebec, NEPOOL provided a cost comparison of the Phase II energy purchases with gas turbines. According to NEPOOL, it selected gas turbines as the alternative to the Phase II energy because the value of the Phase II capacity is its contribution to meeting regional reliability criterion. This is consistent with how gas turbines are generally used by utilities. The NEPOOL analysis concluded that the contract over its life would save $321 million in 1990 dollars over the use of gas turbines to meet regional reliability needs.

To evaluate the cost-effectiveness of Canadian electricity imports as a future source of electricity, we also performed a limited economic analysis comparing the cost of importing Canadian electricity to the cost of constructing coal-fired generating capacity. The purpose of our analysis was to obtain a general indication of the comparative economics of these two alternatives and determine the sensitivity of the analysis to key variables, including oil and coal prices, discount rates, oil and coal generation ratios, and coal-fired generating capacity construction costs. We based our analysis on current import contract pricing provisions reflected in contracts existing in the New England region where electricity is priced on a percentage of avoided fossil fuel generating costs.

In performing our analysis, we projected a base case reflecting the costs of imported electricity relative to the costs of constructing a 1,000-MW, coal-fired generating plant under three oil price assumptions—a high, middle, and low oil price. We also examined the sensitivity of these projections under our middle oil price base case to the above key variables by projecting the relative costs of the electricity supply options using different values for these variables.

In general, our analysis suggests that the alternatives examined are comparable in terms of cost, within the bounds of uncertainty. More specifically, in our base case middle oil price scenario, the cost of imported electricity was 1.5 percent lower than the cost of electricity from a domestic coal plant. The cost advantage of imports was maintained in most of the cases we examined. However, in the case where we assumed high oil prices and the case where we assumed a low discount rate, the coal plant was the cost-effective source by 10 percent and 9 percent, respectively. In addition, the results of our analysis were sensitive to each of the key variables examined. As would be expected, the cost of imports is most sensitive to oil prices; the cost of coal-produced power is more sensitive to discount rates.[2]

[2] A complete description of our analysis is in appendix II.

We recognize certain limitations to our analysis. For example, our analysis included only one way in which electricity imports are priced. We also limited our comparison to the costs of constructing coal-fired generation capacity rather than examining a number of alternative domestic resource options because coal plants have been one of the lowest cost sources of baseload electricity generation in recent years. Thus, our analysis should not be viewed as conclusive, but rather as generally consistent with the results of the previously discussed analyses.

In our view, it is not surprising that imports appear to represent a cost-effective electricity supply option since imported electricity is generally produced from hydroelectric sources. The relatively low cost of hydroelectric power, as previously discussed, provides a significant cost margin between Canadian imports and the power produced in the United States. As long as the cost of imports is based on a percentage of domestic production costs, U.S. utilities can reduce the cost of imports by controlling their own costs. This could be accomplished, for example, by improvements in the operating efficiency of the power system or by replacing old oil-fired units with more efficient or nonfossil-fueled resources.

Given the large, undeveloped hydropower resources remaining in selected provinces, as discussed in chapter 2, it appears that imports will remain an attractive electricity supply resource option relative to developing domestic generating capacity. It is unclear, however, what decisions utilities will make with regard to meeting electricity supply needs beyond their current contractual commitments. These decisions, in our view, will depend in part on the utilities' analyses of the uncertainties associated with developing domestic generating capacity as opposed to increasing their reliance on additional quantities of imported power.

Concern Over Dependency Appears Unwarranted

Concerns related to U.S. dependency on electricity imports appear to focus on two issues: whether the level of imports represented by firm power and firm energy contracts is excessive in relation to domestically supplied power and whether a foreign source, in this case, Canada, will be reliable in meeting commitments to provide power under contract. We found that the level of imports represented by current purchase contracts will not exceed dependency levels considered acceptable by utilities. We also found that the NEB regulates electricity export sales and assures itself that such sales are in excess of Canada's needs. On the basis of these findings, we believe that concerns related to U.S. utilities' overreliance on Canadian electricity in terms of current contractual commitments appear to be unwarranted.

According to regulatory and utility officials and studies and analyses prepared by DOE, utilities, and others, U.S. utilities should continue to use Canadian energy to displace higher cost electricity from domestic generating facilities when possible. The use of imported power results in lower rates to consumers and would reduce U.S. oil consumption to the extent that oil-fired generation is being displaced. However, different views were expressed on what the level of firm power and firm energy commitments should be. Those officials identifying what they believed should be the upper limit of dependency most frequently cited figures in the 15- to 20-percent range of a utility's total capacity requirements.

Our review shows that under existing Canadian firm power and firm energy contracts, the 15- to 20-percent level will not be exceeded. In the NEPOOL and Northern States Power areas where the use of Canadian capacity in lieu of building new power plants will be the most extensive, the contribution of imports to capacity inventories will not exceed 9 percent under existing contracts. If Northern States is successful in its negotiations with Manitoba Hydro to purchase an additional 300 MW of capacity for delivery in the mid-to-late 1990's, its Canadian capacity purchases would still be well below the 15-percent level. Consequently, we believe that by utility standards, U.S. utilities are not in danger of becoming overly dependent on Canadian electricity imports.

We also found that Canada appears to provide reasonable assurance that its electricity export commitments will be met. Current Canadian energy policy on both a provincial and national level encourages the prebuilding of Canadian capacity for export prior to the need for it domestically. By doing this, Canadian consumers benefit from lower power prices. The lower prices are due to the profits realized by Canadian utilities from export sales. These profits are used to subsidize electricity rates in Canada. In addition, the Canadian economy benefits from jobs provided by project construction.

The revenues Canadian utilities receive from exports are significant. In 1983 Manitoba Hydro exported over $100 million worth of electricity. This represented about 23 percent of the utility's total revenues. For Canada as a whole, U.S. exports in 1984 accounted for $1.05 billion in revenues. According to the chairperson of the Manitoba Energy Authority, export revenues contributed significantly towards decreasing and stabilizing the electricity rate structure for provincial power consumers. Ontario Hydro estimates that without export revenues, its rates would have been an average of 5-percent higher between 1975 and 1984. For Hydro-Quebec customers, 1983 rates would have been 15- to 20-percent higher.

NEB regulates power exports from Canada through its export licensing process. Under the 1959 National Energy Board Act, prior to issuing a license, NEB must make two determinations:

1. The power to be exported is surplus to Canadian needs.

2. The price charged is in the public interest.

Regulations adopted to implement the 1959 act established three criteria for determining whether the rate charged for the power is in the public interest. The price must

- recover the appropriate share of the costs incurred to supply the power,
- not be less than the cost to Canadians for equivalent power, and
- be reasonably close to the cost of alternative power and energy available to the purchaser.

Although contract prices are negotiated between the affected utilities, once an export license is applied for, NEB determines whether the negotiated price meets the public interest criteria. Once a contract for electricity is signed and the export license issued, it can be revoked only if conditions of the contract are violated. This has never occurred. Under the 1959 act, NEB authority to revoke or suspend an energy export license in the interest of "public convenience and necessity" specifically does not apply to electricity exports.

To determine whether the power to be exported is in excess of Canadian needs, NEB reviews Canadian utility load forecasts and, if appropriate, utility capacity expansion plans. On occasion, NEB develops its own long-term projections of energy supply and demand in Canada. The latest of these projections was published in September 1984.[3] On the basis of these projections, NEB concluded that because of the availability of Canadian resources and appropriate planning, "there are no inherent

[3] NEB, Canadian Energy Supply and Demand, 1983-2005 (Sept. 1984).

constraints to producing electricity to meet demands considerably higher than the reference case."[4]

Two contracts we examined will require Canadian utilities to build additional generating capacity to meet the contract loads. The Northern States-Manitoba Hydro contract anticipates an advance in the construction schedule of generating facilities on the Nelson River. The Phase II contract between NEPOOL and Hydro-Quebec anticipates the advance of James Bay construction schedules. Because both projects are ongoing construction programs that have the support of both the Canadian provincial and Canadian national governments, we found no reason to question the Canadian utilities' ability to complete the projects and deliver the power as the contracts require.

Although we believe that concerns over Canada's dependability in providing the levels of electricity called for under current contracts are unwarranted, we recognize that in the future the 15- to 20-percent reliance level may be exceeded as domestic utilities' import increasing amounts of power. At that time, in our opinion, utilities will be faced with weighing the implications of exceeding that level in the context of the viability of developing additional domestic resources.

Technical Reliability Concerns Being Addressed

Concerns have surfaced over the technical reliability of power transmissions relative to the movement of power between the Canadian province of Quebec and New England. Our review of information related to New England electricity purchases from Hydro-Quebec disclosed that New England utility representatives have expressed concern about the reliability of Quebec's power system. According to this information, Quebec's electrical system is vulnerable to power outages. In recent years, Hydro-Quebec has experienced 13 partial system failures and 9 systemwide failures. This vulnerability stems from the fact that Quebec's population centers are long distances from the hydroelectric sources that supply them. For technical reasons, long-distance electricity transmission increases the risk of power outages.

In view of the existing situation with respect to Quebec's power system, utilities and regulators have expressed particular concern over the potential reliability impacts of the planned major interconnection between NEPOOL and Hydro-Quebec, which will be required under the newly signed Phase II contract. According to the president of New

[4] The reference case refers to the mid-range Canadian growth projections in the NEB load forecast.

England Hydro-Transmission Company, who is leading NEPOOL's efforts to build, finance, and operate the new transmission interconnection, Quebec has experienced major power outages in the past, and any future outages could spread to interconnected electrical systems such as NEPOOL's. This is an important consideration because when the new interconnection is completed by 1990, it will represent the single largest source of electricity in New England.

NEPOOL is studying the potential effects of the proposed new interconnection as well as ways to improve the overall reliability of interconnections with Hydro-Quebec. NEPOOL is also studying the potential effects of the interconnection on electric systems outside of the New England region. Hydro-Quebec is interconnected with the New England and New York electrical systems. When NEPOOL's planned interconnection with Hydro-Quebec comes on-line in 1990, the total transfer capability between Hydro-Quebec and the United States (including the New England and New York systems) will approach its limit. According to NEPOOL officials, exceeding this limit can result in reliability problems for New England and New York if Hydro-Quebec has a serious outage.

By examining the four major interconnections between Hydro-Quebec and the United States, NEPOOL will also be able to study the new interconnection's potential effects on electrical systems outside the New England region.[5] Because of the Hydro-Quebec system's susceptibility to outages, and the fact that the eastern U.S. transmission system is operating at capacity, NEPOOL is concerned that if all four interconnections failed simultaneously, it could cause reliability problems for the eastern U.S. transmission system.

NEPOOL and Hydro-Quebec are taking steps to improve the reliability of the interconnections, including the following:

- The proposed interconnection between Hydro-Quebec and NEPOOL will be accomplished using a direct current transmission line. A direct current line will protect the interconnection from disturbances in Quebec's alternating current distribution system.
- The utilities are studying ways to ensure that enough electricity reserves are available within New England to handle the loss of a 2,000-MW interconnection.

[5] After 1990, Hydro-Quebec's four U.S. interconnections will include NEPOOL (2,000 MW), New York (1,000 MW), Vermont (200 MW), and New Brunswick/Maine (700 MW). The New Brunswick interconnection is included because Hydro-Quebec is interconnected with New Brunswick, which, in turn, is interconnected with Maine.

- In order to prevent the loss of the interconnection if a serious outage occurred, Hydro-Quebec has developed a "dynamic isolation scheme," which is a series of sensitive switching devices that will detect even slight disturbances in the Quebec system. In the event of a disturbance, this scheme will isolate from Quebec's power system the generators used to supply NEPOOL with electricity and thereby reduce the possibility of losing all four interconnections to the United States simultaneously.

NEPOOL, in conjunction with others, hopes to complete technical studies that address reliability concerns by October 1986.

Limited Capacity for Moving Midwest Power to the Northeast

DOE officials and the governor of New Hampshire have expressed concern over increasing levels of Canadian electricity imports in New England when selected utilities in the Midwest have excess electricity supplies currently available. The concern centers on the ability to move the Midwest power to New England. A NERC study completed in June 1985 disclosed major barriers and existing transmission limitations related to significantly increasing the amount of power moved.[6]

Our discussions with utility officials and review of NERC's 1985 study revealed that the transmission systems between the Midwest and New England are already fully loaded on a daily basis. Thus, although Midwest utilities have generation capability available for sale, existing transmission lines cannot accommodate the increased amount of power. However, steps are being taken to increase the operational capacity of existing transmission facilities in the Midwest. According to the NERC study, these improvements are expected to increase the average economic transfer capability of the Midwest power system from 2,300 MW to about 3,500 MW by the mid-1990's. However, the extent to which this increased capability will result in increased amounts of power being purchased by New England from Midwest utilities will depend on actions taken by utilities that have power systems between the Midwest and New England systems.

In its power transfer analysis, NERC stated that if a significant increase in an interregional power transfer capability were needed, it could only be achieved by constructing major transmission reinforcements at locations between the Midwest and New England power systems as well as within the New England power system. NERC's study identified two technically feasible concepts for transmission reinforcement, both of which

[6] NERC, "ECAR/MAAC Interregional Power Transfer Analysis" (June 1985).

included constructing a new transmission line. NERC's estimate of the preliminary cost to implement these concepts ranged from $.5 billion to $1.1 billion.

Notwithstanding the technical feasibility of transmission reinforcement concepts, NERC's study identified potential impediments to implementing its concepts. These included regulatory, legal, environmental, and financial constraints. According to NERC, each impediment has the potential to delay the completion of a transmission reinforcement to the extent that the economic benefits favoring its completion could disappear. For example, in discussing regulatory and legal considerations, the study noted that many states in the northeastern United States have facility siting legislation and attendant rules and regulations that apply to the construction of high voltage transmission lines. The time required for the application and hearing process for such lines can well exceed the time required to build the facilities. It can be even more difficult when the facilities will serve areas several states away. Recently a task force was formed by 14 governors in the affected regions to investigate this issue.

A final limitation affecting the transfer of power from the Midwest to New England is the length of time excess power will be available in the Midwest. Although Midwest utilities currently have excess power available, the level of the excess will decline as demand grows in the region. On the basis of an analysis in the NERC study, the average amount of economic power available for transfer outside of the Midwest regions during typical nonpeak weekdays is expected to decline from about 7,500 to 8,500 MW in 1986 to between 500 and 3,500 MW in 1994. Therefore, it appears that even if transmission capability were available, the level of excess power available for transfer in the future will be limited.

List of Contacts

Canada

Manitoba	Consulate General of the United States Manitoba Energy Authority Manitoba Hydro-Electric Board Member of the Opposition Party Minister of Agriculture
Quebec	Hydro-Quebec Quebec Ministry of Energy and Resources
Ontario	Ontario Hydro Ontario Ministry of Energy National Energy Board of Canada U.S. Embassy
New Brunswick	New Brunswick Electric Power Commission

Midwest

Utilities and Transmission Companies	American Electric Power Company, Inc. Consumers Power, Inc. Madison Gas and Electric Company Minnesota Power Minnesota Power Cooperative Northern States Power Company United Power Association
State Regulators	Michigan Public Service Commission Minnesota Department of Energy and Economic Development Minnesota Environmental Quality Board Minnesota Public Utilities Commission Public Utilities Commission of Ohio Wisconsin Public Service Commission

Comparison of Future Electricity Cost Projections

In order to evaluate the cost-effectiveness of Canadian imports as a source of baseload electricity supply, we projected the cost to import electricity to New England and compared it to the cost of electricity that could be produced by a newly built coal-fired power plant. We chose a coal-fired power plant to represent a domestic baseload electricity supply alternative because coal plants have been one of the lowest cost sources of baseload electricity generation in recent years.[1] Given the unavoidable uncertainty about future conditions, such as fuel costs, we attempted to determine the circumstances under which imports would be either a more or less expensive source of power than a new domestic power plant. We based our analysis on general conditions facing the New England region because that region currently receives a majority share of Canadian electricity imports and, on the basis of utility load forecasts, expects to need additional electricity supplies by the late 1990's.

For our projection of the costs associated with building and producing electricity from a coal-fired plant, we assumed the construction of a 1,000-MW coal plant, which would become operational in 1995 and produce electricity for 30 years, a common assumption for this type of facility. Capital and operating and maintenance costs for the plant were generally based on projections made by the DOE.

For our projection of the future costs of importing electricity from Canada, we estimated the costs of three components: the "avoided cost" of alternative power sources; the "demand charge," a payment to insure the reliability of the imported electricity; and the costs of new transmission facilities to move the power. We assumed the avoided cost component to be 80 percent of the weighted average costs of fossil fuel for utilities in New England, similar to existing contracts. Our demand charge assumption was also based on an existing contract for imported electricity. Our estimates of the costs associated with transmission facilities were based on estimates provided by utilities.

To compare the costs of the coal plant with those of electricity imports, we converted them into comparable units by calculating the net present value of the stream of all costs of each alternative. The time period of service and the volume of electricity were assumed to be the same for both sources in order to concentrate on differences in the real resource

[1] Energy Information Administration (EIA), Projected Costs of Electricity from Nuclear and Coal-Fired Power Plants, EIA-0356/1 (1982) p. ix.

costs of each.[2] The discounted annual costs of each alternative were added to yield the total net present value of all costs. This value was multiplied by a "levelizing factor" so that the average costs per unit of electricity, which would actually vary over the life of the plant, could be expressed as one value.[3] The levelized costs are therefore the net present value of all costs converted to a per-unit basis, in this case, cents per kilowatt hour.

Finally, we examined the sensitivity of our projections to key variables, including coal and oil fuel costs, used in the projection of avoided costs of alternative power sources, coal power plant construction costs, and discount rates.

Overall, our analysis showed that although it is not possible to determine with great confidence which future source of power would be the least expensive, for most cases examined, the cost of electricity from the coal plant was higher than that for imported power. For example, in a base case middle oil price scenario, the cost of imported electricity was 1.5 percent lower than the cost of electricity from the coal plant. However, in cases reflecting higher oil prices and low discount rates, electricity from the coal plant was less expensive. For example, in our high oil price case, the coal plant electricity was 10 percent cheaper; in the low discount rate case, the coal plant electricity was 9 percent cheaper. In terms of sensitivity, imported electricity was more sensitive to oil prices and electricity from the coal plant was more sensitive to discount rate changes.

Figure II.1 shows the relative cost-effectiveness of electricity imports to electricity produced from a coal plant in our base case comparison under different oil price assumptions.

[2] The time period for both sources was assumed to be 30 years, the approximate working life for a coal-fired power plant. The amount of electricity assumed in each scenario equals the output of a 1,000-MW power plant at a 65-percent capacity factor, or 5,694,000 MWH per year.

[3] The levelizing factor is derived by solving the formula for the net present value of a constant stream for the constant itself. The result is

$$\text{levelizing factor} = \frac{r\,(1+r)^n}{[(1+r)^n - 1]}$$

where r is the discount rate and n is the number of years in the project.

New England

Utilities and Transmission Companies	Bangor Hydro-Electric Company Boston Edison Company Central Maine Power Company Green Mountain Power Company New England Hydro-Transmission Electric Company New England Power Pool Vermont Electric Power Company
State Regulators	Connecticut Department of Public Utility Control Maine Public Utilities Commission Massachusetts Public Utilities Commission Massachusetts Energy Facilities Siting Council New Hampshire Public Utilities Commission Rhode Island Public Utilities Commission Vermont Public Service Board
State Planning Agencies	Connecticut Office of Policy and Management Energy Division New Hampshire Governor's Energy Office Maine Office of Energy Resources Maine Office of the Public Advocate Massachusetts Executive Office of Energy Resources State Consumer Advocate Vermont Department of Public Service

New York and Eastern States

Utilities and Transmission Companies	Allegheny Power Systems, Inc. Consolidated Edison Company of New York, Inc. New York Power Authority Niagara Mohawk Power Corporation Pennsylvania, New Jersey, Maryland Power Pool

State Regulators

State of New York Public Service Commission

National Associations

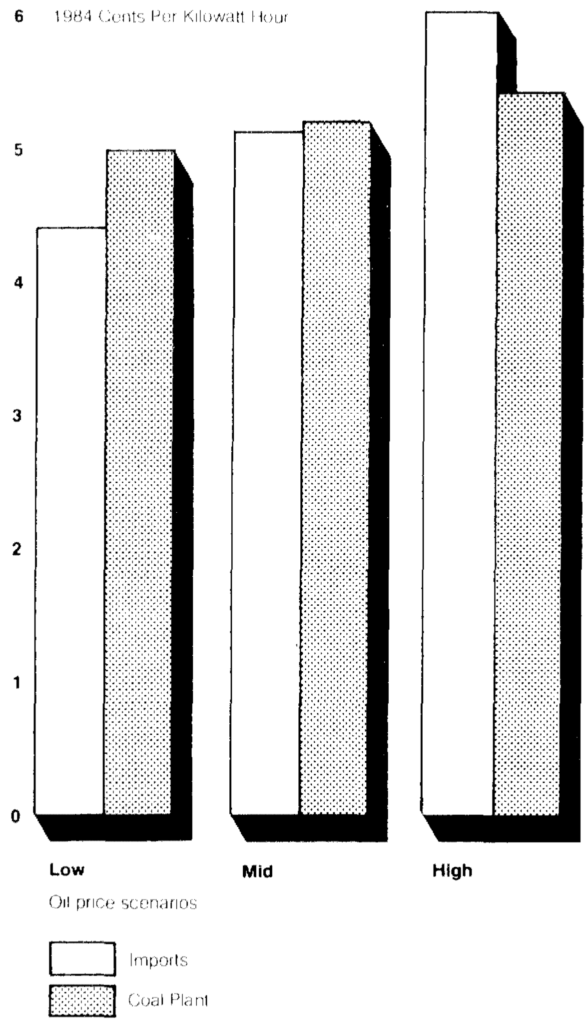
American Public Power Association
Edison Electric Institute
National Association of Regulatory Utilities Commissioners
National Coal Association
National Governors Association
North American Electric Reliability Council
- East Central Reliability Coordination Agreement
- Mid-Continent Area Power Pool
- Northeastern Power Coordinating Council

Federal Agencies

Department of Energy
- Coal and Electricity Policy
- Economic Regulatory Administration
- Office of Environmental Guidance
- Western Area Power Administration

Federal Energy Regulatory Commission

Figure II.1: Base Case Comparison, Levelized Electricity Cost (real)



The following sections provide the details of our analysis.

Cost Estimation for Domestic Coal-Fired Plant

The costs of electricity from a hypothetical 1,000-MW, coal-fired power plant in New England were estimated by separately forecasting the fuel costs, operating and maintenance costs, and capital costs associated with electricity production from the plant. The basic equation for estimating costs associated with the coal plant is

Equation 1

$$RR_t = \frac{K_t + F_t + O\&M_t}{Q_t}$$

where RR_t (the revenue required to cover all costs of producing electricity in year t, expressed on a per-unit basis) equals the sum of K_t (capital cost), F_t (fuel cost), and O&M (operating and maintenance costs) per year, divided by Q_t (the amount of electricity produced by the plant each year of its operating life).

We calculated the amount of electricity produced by multiplying the plant's capacity (1,000 MW) by the number of hours in a year (8,760) and by an operating capacity factor to reflect the proportion of time during which the plant would be operating. We assumed the capacity factor would be a constant 65 percent over the life of the coal plant, the same value assumed by EIA.[4] Thus, we assumed that the plant would produce a constant 5,694,000 MWH in each of the 30 years of its operating life.

Our analysis relied on published estimates of fuel and operating and maintenance costs, and on a DOE model used to estimate capital costs of electricity from the coal-fired plant. Operating and maintenance cost estimates are from a 1982 EIA report.[5] The costs consist primarily of salaries and wages of on-site personnel and, according to EIA's study, comprise about 9 percent of a coal plant's total costs. Fuel cost projections are drawn from Data Resources Incorporated (DRI) and from forecasts by DOE's Office of Policy, Planning, and Analysis. Coal fuel cost estimates also play an important part in the imported electricity cost projections and are described in detail in the section, "Cost Estimation for Imported Electricity."

Capital Costs

We estimated capital costs of electricity from the coal-fired power plant using a modified revision of DOE's National Utility Financial Statement model, which simulates power production costs, including a fair rate of return on the original cost of a facility.[6] The annual capital costs were estimated for each year of the plant's operating life, assumed to be 1995 to 2024. These costs were discounted to present value dollars in the initial year of operation. The net present value of capital costs was then

[4] EIA (1982) p. xi.

[5] EIA (1982) p. xi.

[6] ICF, Inc. Documentation of the National Utility Financial Statement Model, Vol. 1 (1984).

converted to levelized costs per unit of electricity using the levelizing factor described earlier. Equation 2 is the formula generally used to estimate the capital cost component of the coal plant's annual revenue requirements.

Equation 2

$$K_t = r(RB_t) + SD_t + T_t - (ITC/n)$$

The annual capital costs (K_t) are the sum of the return on investment ($r(RB_t)$), where r is the weighted average rate of return on capital and RB_t is the rate base, or the value of the utility's investment; the net depreciation (SD_t); the federal income tax payments (T_t); minus the amortized value of the Investment Tax Credit on the utility's investment in the plant (ITC/n).

We assumed a constant value for the utility's cost of capital of 11.96 percent on the basis of recent forecasts by EIA.[7] This represents the average cost of debt and equity to the utility. We also assumed a straight-line depreciation of the plant equal to the initial capital expenditures on the plant divided by the number of years in its operating life.

The Investment Tax Credit equals a percentage (currently 10 percent on most assets) of construction expenditures during each year of the construction period.[8] Under normalization accounting the credit is deferred and amortized over the life of the plant. Thus, the utility realizes the credit in the year the expenditures are made, and revenue requirements are reduced by ITC/n in each year of plant operation, where n is the number of years.

The following section explains the calculation of the adjusted rate base and the federal income tax term.

Adjusted Rate Base

The adjusted rate base is calculated using the following formula:

Equation 2.1

$$RB_t = K_0 - CD_t - DT_t$$

[7] EIA, Analysis of the Projected Electricity Prices to 1995 (Aug. 1985) p. 36.

[8] ICF, Inc., p. 23.

where K_0 is the capital investment as of the initial date of plant operation. It includes the direct construction expenditures and the interest expense on funds used in construction, called the Allowance for Funds Used During Construction (AFUDC). On the basis of recent EIA publications and industry sources, we estimated construction costs (including AFUDC) at $1,370 per kilowatt in 1984 dollars.

CD_t is the cumulative straight-line depreciation of the initial capital investment, calculated as follows:

Equation 2.1.a

$$CD_t = \sum_{i=1}^{t} SD_i$$

where SD_i is the current straight-line depreciation.

DT_t (equation 2.1) is the account for accumulated deferred taxes. The deferred tax account reflects the "normalization" of tax benefits, by which the regulatory commission causes the lowered tax liability due to various tax law provisions to be accumulated as accrued by the utility, and distributed over the life of the power plant by reducing the adjusted rate base. This account is made up of two components: deferred taxes due to accelerated depreciation for tax purposes (DAD_t), and deferred taxes due to the deductibility of the interest portion of AFUDC ($DAFDC_t$). Equation 2.1.b shows this relationship.

Equation 2.1.b

$$DT_t = DAD_t + DAFDC_t$$

Accelerated depreciation lowers tax liabilities in the early years of the plant's operation but raises them in later years, relative to straight-line depreciation. Thus, the DAD_t is the sum of the differences in taxes owed under the two forms of depreciation, as shown in the following equation:

Equation 2.1.b.i

$$DAD_t = \sum_{i=1}^{t} z(AD_i^{tx} - SD_i^{tx})$$

where z is the federal income tax rate applying to utilities, and AD is the annual value of depreciation under acceleration allowed by current tax laws. The superscript "tx" indicates that the capital investment defined for income tax depreciation is different from that defined above. See the "Federal Income Taxes" section for an explanation of the differences.

Deductibility of the interest portion of the AFUDC means that the value of the tax deduction is realized by the utility (in lower tax payments) during the construction period. Thus, at the beginning of plant operation, the account equals

Equation 2.1.b.ii

$$DAFDC_0 = \sum_{j=k}^{m} z(AFUDC_j * s_d)$$

where s_d is the fraction of construction expenditures financed by debt, and j = k, ... m are the years during construction of the plant. This amount is then amortized by the regulatory commission over the operating life of the plant at a constant rate ($DAFDC_0/n$). The starting account is then reduced by this annual amortized amount each year:

$$DAFDC_t = DAFDC_{t-1} - (DAFDC_0/n)$$

Federal Income Taxes

Federal income tax liability is based on the utility's net income on its capital investment. The deductions from gross revenue for tax purposes include the amortized tax savings described in the previous section, the interest expense portion of the cost of capital, and the current depreciation for tax purposes. Under normalization accounting, the depreciation deduction for tax purposes is the straight-line depreciation of the qualifying capital investment. The latter excludes AFUDC and one-half of the Investment Tax Credit on the original construction expenditures. The equation for tax liability, when simplified, becomes

Equation 2.2

$$T_t = (z/1-z)[r_e s_e RB_t + SD_t - (ITC/n) - (DAFDC_0/n) - SD^{tx}_t]$$

where r_e is the utility's allowed rate of return on equity capital, and s_e is the fraction of capital expenditures financed by equity.

Cost Estimation for Imported Electricity

The cost of future electricity imports to New England is estimated as the sum of three components: the "avoided cost" of alternative power sources; the "demand charge," a payment to ensure the reliability of the imports; and the cost of new transmission facilities to carry the power.

The avoided cost component is computed as 80 percent of the weighted average cost of fossil fuel for utilities in New England. Forecasts of fossil fuel costs through the year 2010 were drawn from the Long Term Energy Review forecast by DRI. These forecasts include low and high oil price scenarios as well a base case. For the years 2010 to 2025, we forecasted oil and coal prices by constructing our own growth rates. We considered the rates of growth forecasted by DRI and DOE's Office of Policy, Planning, and Analysis in constructing our estimates. The assumed growth rates of oil and coal prices are listed in table II.1.

Table II.1: Average Real Growth Rates of Fossil Fuel Prices

Percentage per year

	Base case		Low oil price		High oil price	
	Oil	Coal	Oil	Coal	Oil	Coal
1985-1995	−.8	1.5	−1.8	1.1	2.4	2.5
1996-2010	4.2	−.6	3.2	−.9	3.7	−.7
2011-2025	3.4	1.0	2.8	1.1	2.6	.8

In calculating the weighted average cost of fossil fuel to electrical utilities in New England, the assumed shares of oil-fired and coal-fired generation are important inputs. The base case assumes that the shares are equally divided, with 50 percent of the fossil-generated power from each fuel. Current shares of fossil generation in New England are about 30 percent from coal and about 70 percent from oil. As discussed later, we varied this relationship to determine its influence on the cost-effectiveness of electricity imports.

The costs of new transmission capacity that could be associated with a large import contract are based on estimates provided by utilities and are modeled like the other capital expenditures discussed previously, i.e., they are incorporated into the rate base and amortized over a 30-year period. The base case assumes construction costs of $540 million (in 1984 dollars) for facilities to carry an amount of electricity comparable to that from a 1,000-MW power plant.

The demand charge is a fee associated with the purchase of firm imported power. The fee is charged on an annual basis and converted to cents per kilowatt hour by dividing the fee by the annual quantity of electricity purchased. The base case value, $51.36 million per year in the initial year for imports of 1,000 MW, is based on similar terms in an existing contract for a smaller amount of imported power.[9]

As in the case of the coal plant, we estimated the annual value of each these cost components for the period 1995 to 2024. We discounted the costs to 1995 and levelized them using the same levelizing factor. Thus, the formula for imported electricity levelized costs as estimated in our analysis is

$$Ci = .8[.5(Po) + .5(Pc)] + TC + PC$$

where Po and Pc are the levelized cost of oil and coal to electric utilities in New England, TC is the levelized costs of the transmission facilities, and PC is the levelized value of the annual demand charges.

Sensitivity Analysis

Given the uncertainties inherent in forecasting future values of several important variables, we examined the sensitivity of the results to the assumed values of three key variables. Our results are discussed in this section.

1. Oil and Coal Shares of Fossil Fuel Electricity Generation

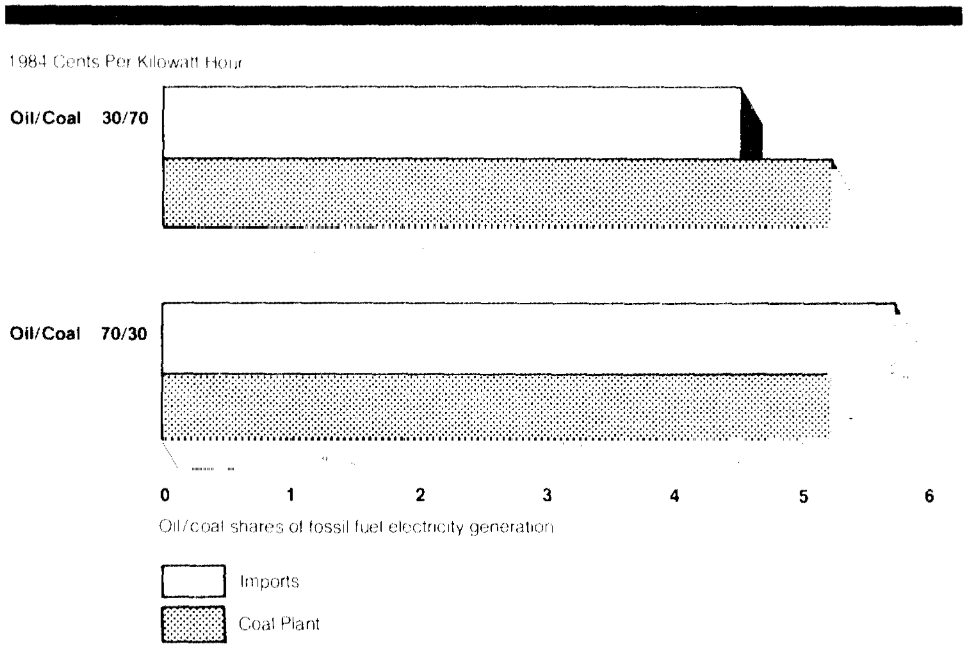
Because of the significant differences between coal and oil fuel costs, the assumed proportion of each in New England's power generation is an important unknown in calculating avoided fossil fuel costs. The avoided fossil fuel cost, in turn, is an important component of imported electricity costs under the cases we examined. In general, the higher the share of oil, the higher the cost of imports.

We examined three forecasts of fossil fuel shares in our analysis. A NERC forecast predicted that the oil-share to coal-share ratio of New England's fossil fuel-fired electricity generation would be about 50/50 by the year 1993. NEPOOL's forecast projected oil/coal ratios of about 60/40 in 1995, increasing to 70/30 in 2000. The DRI forecast predicted that the oil/coal share will decline from 67/33 in 1990 to 30/70 in 2000. DRI also projected a further decline in the share of oil beyond the year 2000.

[9] The state of Vermont currently has a contract for 150 MW of firm power with Hydro-Quebec. The annual demand charge under this contract is $10 million. Under a 1,000-MW contract, at the same dollars per megawatt, the annual demand charge would be $51.36 million in 1984 dollars.

Clearly, different sources are predicting widely different values. To demonstrate the effect of different values on the projected costs of imports, the base case value of 50/50 was changed to 70/30 and 30/70. The effect of these assumptions on the cost of imports under the middle oil price scenario are compared with coal-fired power costs in figure II.2.

Figure II.2: Sensitivity of the Relative Cost of Imports to Fossil Shares, Evaluated at Middle Oil Prices (levelized costs)



As figure II.2 indicates, the cost-effectiveness of imports as compared with coal-fired domestic generation is changed by altering the assumed shares of oil and coal in total fossil fuel generation. The imports are cheaper when oil's share is 30 percent, but they are about equal in cost when oil's share is 70 percent.

The results in figure II.2 may exaggerate the influence of the generation shares on imported electricity cost projections because the shares of generation from oil and coal are influenced by the prices of oil and coal, but this interdependence has not been modeled here. Since a complete model of energy supply and demand was not available for this analysis, the sensitivity of import costs to each variable, that is, fuel prices and shares of fossil fuel generation, can only be discussed separately. For example, if oil prices rise quickly, causing the cost of imports to rise, the share of oil would likely fall, offsetting the cost increase to some extent.

Similarly, the falling or slowly rising oil prices will lead to larger oil shares, dampening the associated decrease in the cost of imports.

We also examined the change in forecasted fossil fuel shares under different oil price scenarios in the DRI forecast. We found that the shares of oil and coal differed by less than five percentage points from the low to the high oil price scenario. Because of the differences in approach to forecasting, however, we think these results should be confirmed by comparison with other forecasts, which was not possible for this study.

2. Coal Power Plant Construction Costs

The total construction cost of a coal-fired power plant is another important variable in our electricity cost projections. Total construction costs are affected by uncertainties such as future pollution control requirements, construction lead times, borrowing costs, and the cost of other components of construction. A 1982 EIA study projected construction costs of a 1200-MW, coal-fired generating plant coming on line in 1995 to be $1,160 per kilowatt in 1984 dollars.[10] A study by the United Engineers and Constructors estimated construction costs of a 1,000-MW, coal-fired generating plant to be $1,575 per kilowatt in 1984 dollars. A 1985 report by the American Gas Association projected construction costs for 500 MW of coal-fired capacity to average $1,200 to $1,400 per kilowatt over the period 1985-90. A Canadian Energy Research Institute study estimated coal plant construction costs of $1,370 per kilowatt.[11]

Our base case assumed a mid-range value for the cost to construct a coal plant of $1,370 per kilowatt. The high cost case assumed construction costs of $1,790 per kilowatt and the low cost case assumed $1,160 per kilowatt. The high estimate is based on a recently completed coal plant in the Northeast, assuming real cost escalation of 2 percent per year.[12] This is the same real escalation factor assumed by EIA in its 1982 study. The effects of varying coal power plant construction costs on the cost comparison with imports is shown in figure II.3.

[10] EIA (1982) p. xi.

[11] Canadian Energy Research Institute, "Potential Benefits and Costs of Canadian Electricity Exports," Vol. II (Dec. 1982) p. 62.

[12] The plant referred to is the Somerset plant in New York State.

Figure II.3: Sensitivity of the Relative Costs of Imports to Coal Plant Construction Costs, Evaluated at Middle Oil Prices (levelized costs)

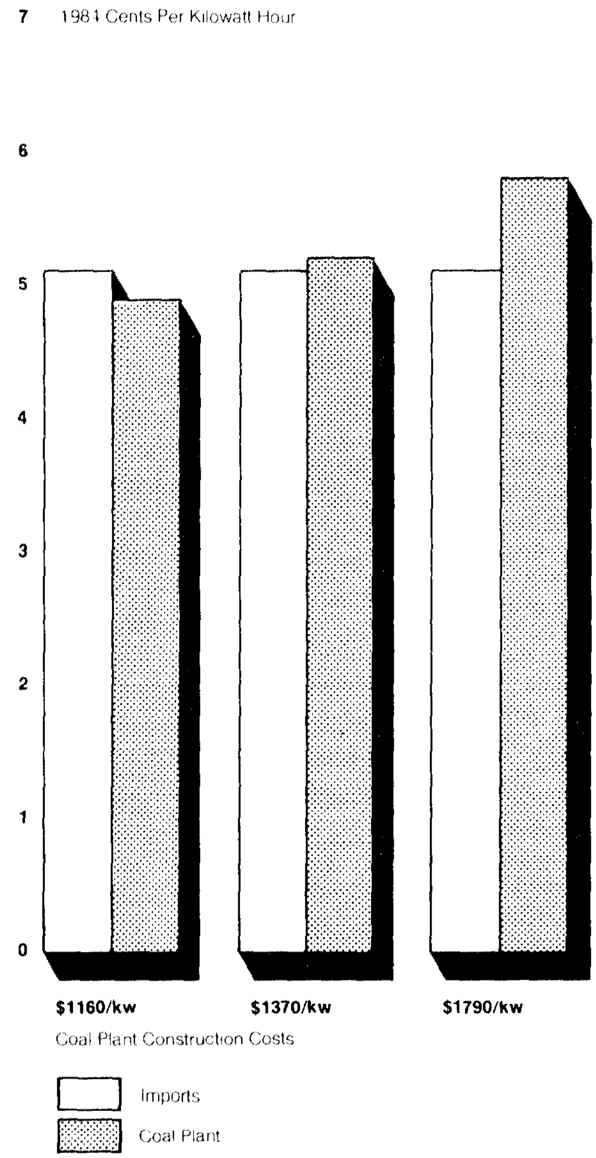


Figure II.3 demonstrates that the relative cost-effectiveness of electricity imports is affected by the values assumed for coal plant construction costs. For example, the coal plant was the cost-effective source in the low construction cost case, but was the higher cost source in the other two cases.

3. Discount Rates

An important uncertainty in any analysis that seeks to compare costs over long periods is the appropriate discount rate to use in discounting dollar amounts from future time periods into equivalent current dollar amounts. To demonstrate the sensitivity of the cost comparison to this variable, we assumed a range of values that represents different opinions on the subject. The lowest value assumed was 1 percent in real terms, based on an estimate of the social rate of time preference, or society's average interest rate on savings.[13] The highest value assumed was 10 percent in real terms, based on an estimate of the before tax marginal rate of return on low-risk private investment in the economy.[14] The base case assumed a real discount rate of 4.92 percent. This rate was derived from an average of yields on U.S. Treasury securities maturing during the time period 1995-2015, which covers the first half of the analysis.

The effects on electricity costs of varying the discount rate are shown in figure II.4.

[13] Lind, R.C., Discounting for Time and Risk in Energy Policy (Resources for the Future, 1982) p. 87.

[14] Lind, R.C., p. 81.

Figure II.4: Sensitivity of the Relative Costs of Imports to the Discount Rate, Evaluated at Middle Oil Prices (levelized costs)

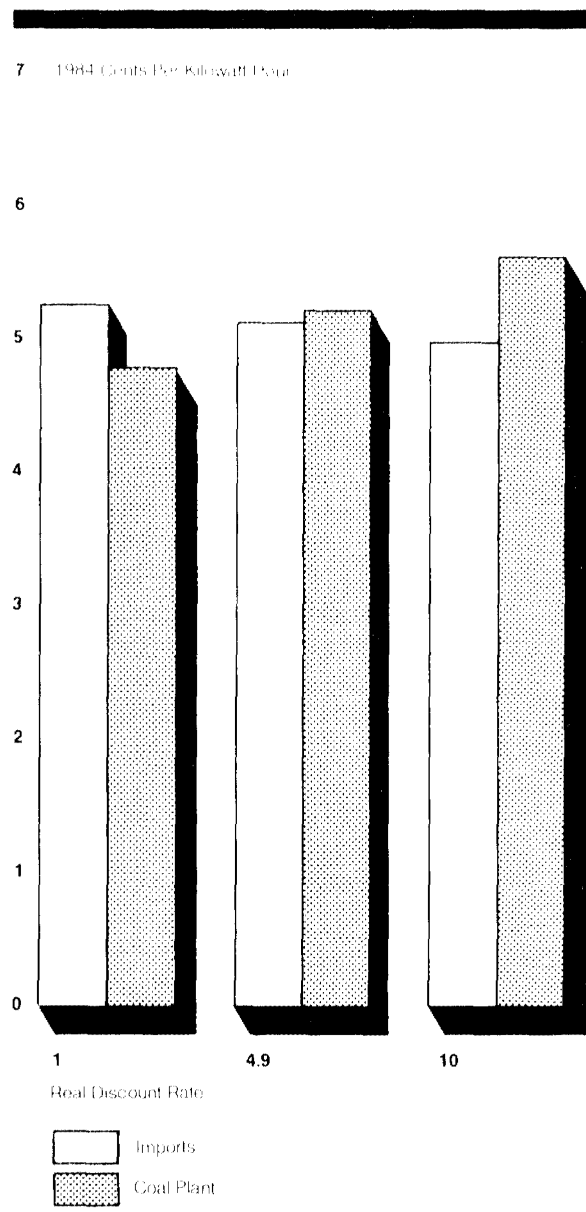


Figure II.4 shows that the levelized cost advantage of the coal plant disappears as the discount rate is increased to 4.9 percent as well as to 10 percent in real terms. This reflects the fact that capital costs of the coal plant are higher in the early years of operation and fall over time as the plant is depreciated. Thus, the higher the discount rate, the more heavily the annual average cost advantage of the coal plant in the later years is discounted.

Interpreting the Results

The results of this analysis must be interpreted cautiously because of the hypothetical nature of several important factors. One qualification concerns the formula for pricing Canadian electricity imports. The formula used in our analysis is only one example of how imported electricity could be priced. As such, it reflects a set of supply and demand conditions that may or may not reflect the future. Thus, conclusions about these results should be limited to statements about the specific import pricing method that we analyzed.

Other qualifications concern the data used in the analysis. Figures II.1 and II.2 show that the comparison of coal plant costs with import costs depends to a significant degree on the future prices of oil and coal to utilities, and on the future shares of fossil fuel-fired generation accounted for by each. Both of these are highly uncertain. The instability of crude oil prices and the difficulty of predicting even near-term supply and demand shifts have become increasingly clear in recent months.

The projections in our analysis were developed before the recent oil price decline and are probably somewhat higher than current projections, at least in the early part of the forecast. For example, current spot market prices are about $13 per barrel, while the prices forecast in the middle price case would be about $24 per barrel in 1990. As our results show, imports' costs are more sensitive to fuel prices than the coal plant's. Therefore, if the projections used here were updated, they would imply lower costs for imports relative to the coal plant's.

Additional Considerations

Utility planners are concerned with not only the levelized costs of a particular power source but also the stream of costs over time. The stream of costs over time reflects more closely the impact of power costs on utility rate-setting. Thus, a utility could be expected to prefer a relatively "smooth" stream of costs to one that is "front-end loaded", i.e., higher in the early years. The latter stream forces the utility to ask for significant rate increases in the early years, which would likely excite opposition from consumers, and reduce the quantity of electricity purchased.

Figures II.5 and II.6 demonstrate that electricity imports and electricity from a coal plant exhibit very different streams of costs over time. The coal plant's costs are higher in the early years because capital costs are included in the rate base. The costs drop as these capital costs are depreciated. Electricity imports, under the prices we assumed, are higher in later years because of the gradual escalation of fuel prices over time.

Figure II.5: Time Pattern of Electricity Costs: Real, Evaluated at Middle Oil Prices

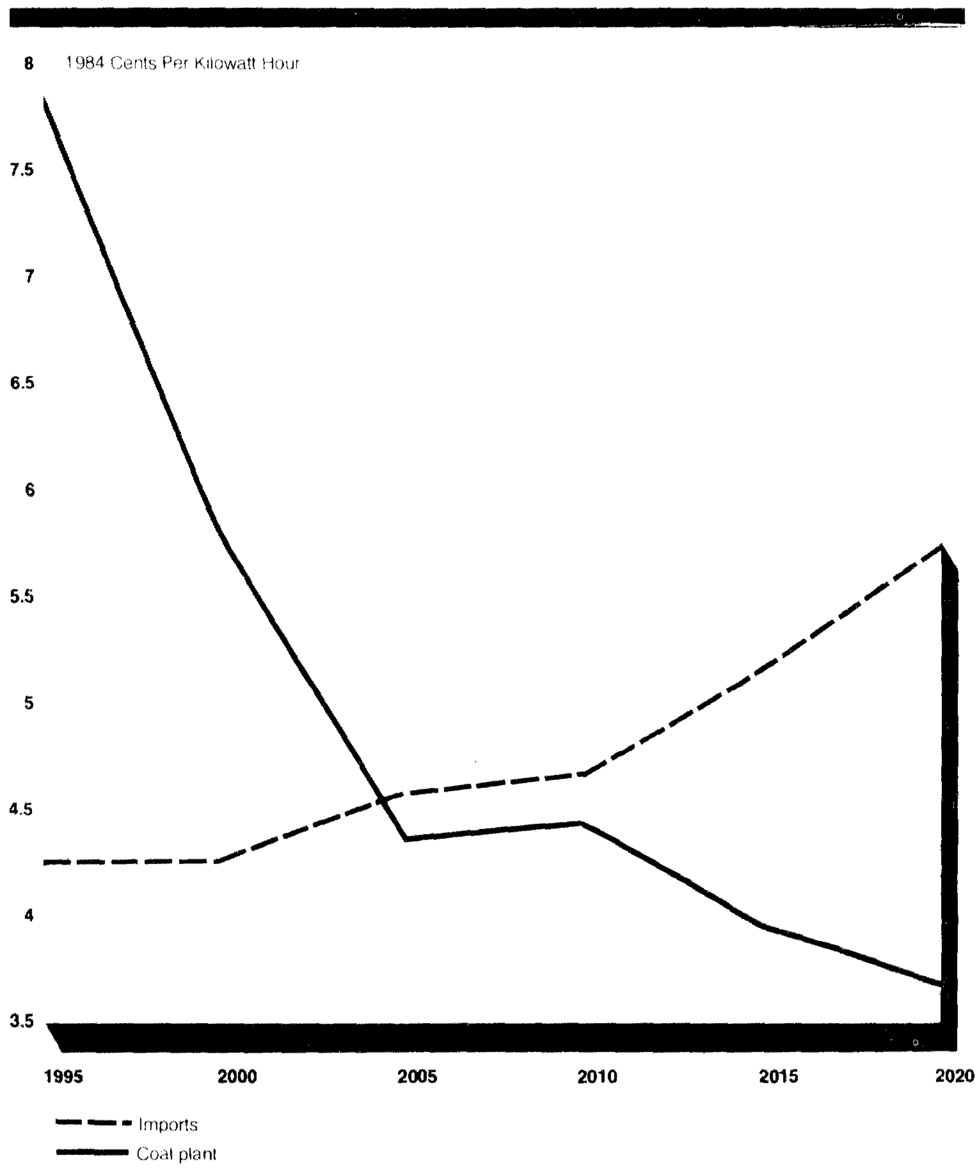
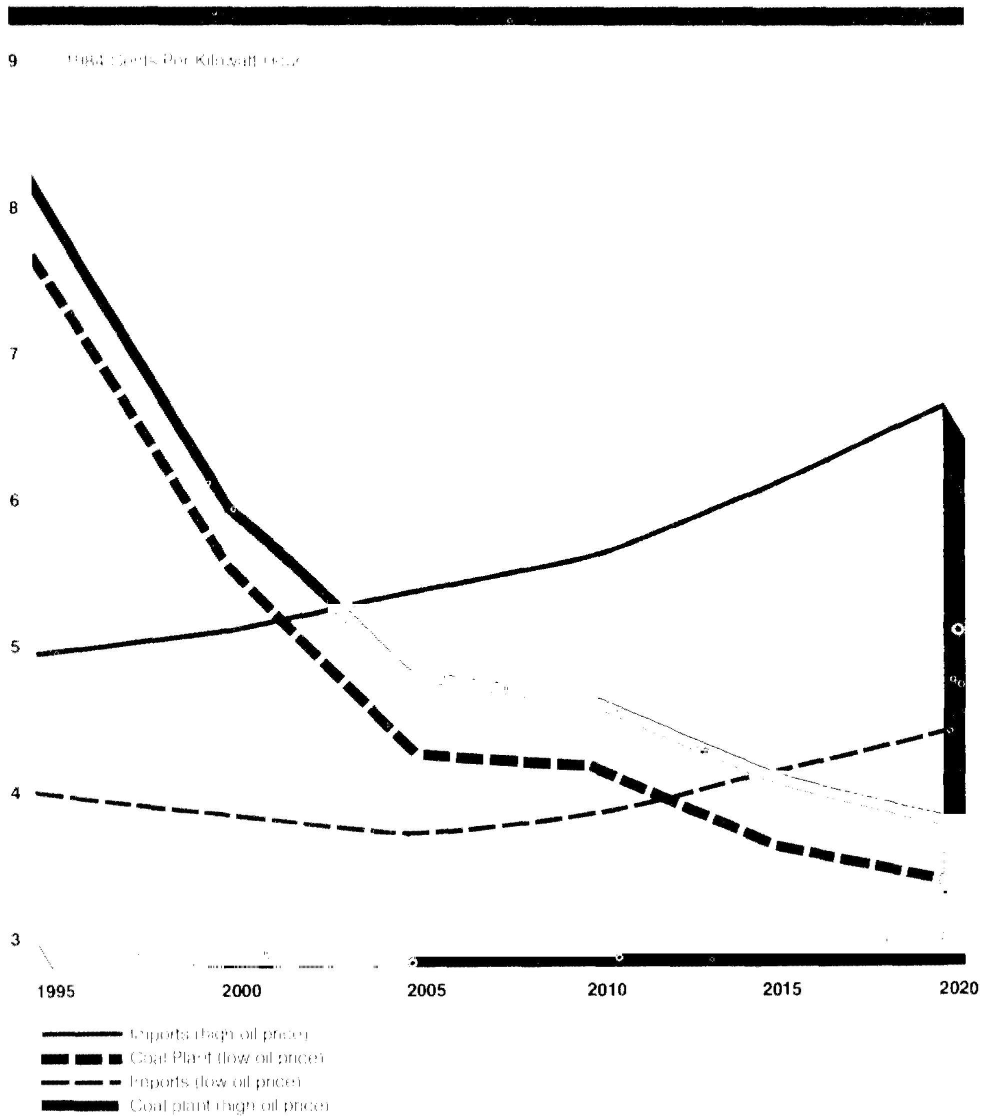


Figure II.6: Time Pattern of Electricity Costs: Real, Evaluated at Low and High Oil Prices



Federal Activities Related to Canadian Electricity

At the request of the Chairman, Subcommittee on Oversight and Investigations, House Committee on Energy and Commerce, we reviewed and obtained information on DOE's program activities and levels of staff with respect to Canadian electricity imports. In August 1985 we briefed the Chairman's office on the preliminary results of this work.

The following describes DOE's administration of the Presidential Permit process, its activities to monitor compliance with conditions of issued permits, and the number of staff devoted to carrying out Presidential Permit activities.

Presidential Permit Process

Current federal activities related to electricity imports primarily result from Executive Order 10485, which requires that the construction of an electrical transmission line crossing the U.S. international border be licensed (Presidential Permit). DOE is the federal agency currently responsible for issuing Presidential Permits.

The purpose of the Presidential Permit is to ensure that the "territorial integrity" of the U.S. is protected. According to DOE, "territorial integrity" means that any connection linking the U.S. to a foreign country will have no adverse effects on the physical territory of the U.S.

The use of Presidential Permits began in 1939 and permits originally required the President's signature. Between 1953 and 1977, the Federal Power Commission issued the permits. DOE has been issuing the permits since its formation in 1977. As of October 31, 1985, a total of 15 permits and three amendments to permits had been granted by DOE and were in effect.

DOE administers the Presidential Permit process by reviewing permit applications submitted by utilities or others who are planning to construct transmission lines that cross the U.S. borders. In its review of applications, DOE applies two criteria and receives input from the Departments of Defense and State to determine whether granting the permit will protect the territorial integrity of the United States and will be consistent with the public interest. The two criteria DOE applies in its review are an environmental impact evaluation and an assessment to determine whether the proposed transmission facility will adversely affect U.S. electrical power system facilities (a technical reliability assessment).

A description of DOE's review process and the roles of the Departments of Defense and State follows.

Environmental Impact Evaluation

According to DOE, the National Environmental Policy Act of 1969 (NEPA) requires a review of the environmental impacts of the proposed transmission facilities. DOE requires each applicant to submit information regarding the environmental impacts of the proposed interconnection facility. This information includes a list of floodplains, wetlands, critical wildlife habitats, navigable waterway crossings, Indian lands, and historic sites that may be affected by the facility. In addition, the applicants' environmental report is required to include details regarding the minimum right-of-way width required by the transmission line, a list of threatened or endangered wildlife or plant life that may be affected by the proposed project, and a description of all reasonable alternatives to the proposed project and a discussion of their environmental impacts.

On the basis of information provided by the applicant, DOE's Office of Environmental Compliance determines what level of analysis needs to be done. The three levels of analysis are (1) an immediate finding of no significant environmental impact, (2) an environmental assessment, if it is unclear whether there is a significant environmental impact, and more information and study needs to be done to make a decision, and (3) an environmental impact statement (EIS), when it is clear there is a definite significant impact. If an environmental assessment must be completed, either DOE or an outside consultant may do the work. The environmental assessment may find (1) no significant impact or (2) that there are significant impacts to the extent that an EIS is required.

If DOE determines that the interconnection could have a significant environmental impact, as defined under NEPA and its implementing regulations, a draft and final EIS is prepared. This usually is contracted out to one of DOE's national laboratories. The applicant may request that its own contractor prepare the EIS; however, DOE must approve the contractor to ensure that it has the capability of preparing an acceptable document and that no conflict of interest exists. The EIS must be approved by DOE and ultimately becomes their document. The public may comment on both the draft and final EIS. On the basis of findings in the EIS, before receiving a permit, the applicant must make modifications to its proposal to minimize the impacts identified. Of 15 permits issued since October 1977, DOE has required an EIS in 5 cases.

Technical Reliability Assessment

In performing its technical reliability assessment, DOE applies regional electric reliability standards developed by NERC. The NERC regional reliability councils have established reliability criteria with which interconnected utilities are expected to conform, to ensure that interconnected power systems remain within acceptable voltage, loading, and stability limits during normal and emergency conditions.

In determining the technical reliability of a proposed interconnection, DOE first reviews technical information supplied by the applicant to determine the scope of reliability issues and to develop an outline for the reliability analysis. DOE may either ask the applicant for additional information or have the application reviewed by an outside consultant. Public comments are then solicited (usually from utilities, power pools, and NERC in the reliability review). DOE makes a staff reliability determination that includes a recommendation for approval or denial. The permit is issued with conditions attached to ensure reliability.

Roles of the Departments of Defense and State

In addition to DOE's environmental and reliability reviews, Executive Order 10485 requires DOE to obtain concurrence from the Secretaries of State and Defense before a permit is issued. DOE provides State with a description of the transmission facility and a description of any conditions of the permit, and DOE's recommendation for approval. State evaluates the information for foreign policy impacts, including (1) overall trade relations, (2) open access to each country's energy markets, and (3) reduced trade barriers. To date, state has concurred with every DOE approval recommendation.

Defense evaluates the permit information provided by DOE for national security impacts. Defense seeks concurrence from the particular service branch that may have a military installation located near the transmission facilities. To date, Defense has followed every DOE recommendation for permit approval.

DOE Compliance Activities

Utilities are required, as a condition of the Presidential Permit, to report annually to DOE the amount of electricity imported and exported over the licensed interconnection. Utilities are also required to report the dollar amounts of the electricity transactions on a monthly basis. Further, utilities must report any change in interconnection ownership or in the physical configuration of the transmission line. In our review of DOE records we found instances where required information had not been promptly reported. As of October 1985, DOE had resolved these matters.

DOE relies on the voluntary cooperation of permit holders to comply with the terms and conditions of the permits. DOE does not conduct any specific monitoring activities on its own to ensure that all permit conditions have been met.

In our work, we reviewed DOE permit files and compared information in DOE records with information provided to us by the Canadian government. On the basis of this work, we noted a case where a utility had given DOE inaccurate information, but DOE had subsequently taken corrective action. We also noted minor inconsistencies in our comparison of DOE and Canadian information. Subsequent to our disclosure to DOE of these inconsistencies, DOE contacted the appropriate utility and corrected the problem. A brief summary of these matters follows.

In 1970 Vermont Electric Cooperative purchased from International Electric Cooperative several low-voltage transmission lines that had received permits. However, the change in ownership was not reported as required. In March 1979 DOE notified Vermont Electric Cooperative that it appeared to be operating electrical facilities at the U.S./Canadian border without a permit. DOE records indicated that the cooperative's management was not aware that permits were nontransferable. Following the DOE notification, the cooperative applied for a permit for their transmission lines, and DOE issued a permit.

In comparing DOE and Canadian information, we noted inconsistencies in data related to several utilities. On the basis of our findings, DOE followed up with one utility and NEB. It found that the utility was operating its permitted transmission lines at voltage levels lower than allowed for in the permits. In addition, some small interconnections were torn down, but the utility never notified DOE. Following the DOE inquiry, the correct information was reported.

Finally, in our comparison we noted discrepancies in data related to a number of lower voltage transmission lines crossing the U.S./Canadian border. Both U.S. and Canadian utilities sell electricity to small customers across the border where these customers are remote from the nearest power system in there own country. Some of these lines provide electricity for only a single farm, private residence, or summer cottage. While DOE recognizes the disparity between its data and Canada's relating to these lines, a DOE official told us that because of the insignificance of the disparities, they believe no further action is warranted. NEB does not consider these lines interconnections and only mentions them for completeness.

DOE Program Staffing and Other Program Data

Since being transferred to DOE, the Presidential Permit function has been combined with other DOE program functions. According to DOE program staff, from 1977 to 1982 the permit process was administered by only one or two staff members on a part-time basis. Since 1983 the number of permit applications has increased, resulting in a fiscal year 1985 budget of about $600,000 and a staff of five full-time employees. Similar resource levels were requested for fiscal year 1986. DOE officials believe that on the basis of the past 2 years' experience, these levels of funding and staff are adequate to handle the work load, which ranges from 5 to 6 permit applications per year.

DOE has received 18 applications for Presidential Permits and 4 amendment applications since 1977, and has issued 15 permits and 3 amendments. As of October 31, 1985, a total of 79 Presidential Permits had been issued to 41 permit holders since the program began. The amount of time between receipt of an application by DOE and the permit issuance has ranged from 3 to 16 months for permits where an EIS has not been required, and from 15 to 28 months when an EIS was required.

Glossary

Alternating Current (AC)	An electric current that reverses its direction of flow periodically (see direct current).
Avoided Cost	The costs an electric utility would otherwise incur to generate power if it did not purchase electricity from another source.
Blackout	The disconnection of the source of electricity from all the electrical loads in a certain geographical area.
Capacity	Maximum power output, expressed in kilowatts or megawatts. Equivalent terms: peak capability, peak generation, firm peakload, and carrying capability. In transmission, the maximum load a transmission line is capable of carrying.
Capability	The net average output ability of a generating plant or plants during a specified period, in no case less than 1 day. Capability may be limited by available water supply, plant characteristics, maintenance, or fuel supply.
Cogeneration	Generally, the dual use of steam, heat, or resultant energy for an industrial, commercial, or manufacturing plant or process and for electricity generation.
Demand Charge	That portion of the charge for electrical service based on the percentage of electrical capacity consumed and billed on the basis of an applicable rate schedule.
Direct Current (DC)	Electricity that flows continuously in one direction (see alternating current).
Economy Energy	Energy produced and supplied from a more economical source in one system and substituted for that produced or capable of being produced by a less economical source in another system.

Economy Energy Transaction	A generating unit on one system is used to supply the next increment of load on another system, thereby allowing the receiving system to avoid supplying that increment of load with a higher cost unit of its own.
Energy Charge	That portion of the charge for electrical service based on the electrical energy consumed or billed.
Firm Energy	Energy that obligates the seller to supply and the buyer to accept a fixed amount of energy over a given period of time. The instantaneous power may vary from hour to hour, but the total energy contracted for will be delivered over a contract period (usually 1 year).
Firm Power	Power intended to be available at all times during the period covered by a commitment, even under adverse conditions, except for reason of certain uncontrollable forces or service provisions. Equivalent terms: prime power, continuous power, and assured power. Component terms: firm energy, firm capacity, and dependable capacity.
Generating Plant	A plant containing prime movers, electrical generators, and auxiliary equipment for converting mechanical, chemical, and/or nuclear energy into electrical energy.
Generating Unit	An electrical generator together with its prime mover.
Hydroelectric	An electrical generating power plant in which the prime mover is a water wheel. The water wheel is driven by falling water.
Incremental Cost	The increase in the cost of generating or transmitting electricity above the base amount.
Interconnection	A connection between two electrical systems permitting the transfer of electrical energy in either direction.

Interconnection Agreement	An agreement between systems that establishes guidelines for mutual assistance. This assistance typically provides for economy transactions, emergency assistance, sale of surplus energy, and the coordination of equipment maintenance and other day-to-day operations.
Interruptible Power	Power made available under agreements that permit curtailment or cessation of delivery by the supplier.
Kilovolt (kv)	A unit of electrical power equal to 1,000 volts.
Kilowatt (kw)	The electrical unit of power equal to 1,000 watts.
Kilowatt Hour (kwh)	A basic unit of electrical energy equal to 1 kilowatt of power for 1 hour.
Load	An amount of electrical power delivered to a given point on a system.
Load Management	Influencing the level and state of the demand for electrical energy so that demand conforms to individual present supply situations and long-term objectives and constraints.
Megawatt (MW)	A unit of electrical power equal to 1 million watts.
Megawatt Hour (MWH)	A unit of electrical energy equal to 1 megawatt of power applied for 1 hour.
Outage	In a power system, the state of a component (such as a generating unit or transmission line) when it is not available to perform its function because of some event directly associated with the component.
Peak Demand	The greatest demand that occurs during a specified period of time

Prime Mover	The engine, turbine, water wheel, or similar machine that drives an electric generator.
Real Power	The rate of supply of energy, measured commercially in kilowatts.
Reliability	Generally, the ability of an item to perform a required function under given conditions for a given time period. In a power system, the ability of the system to continue operation while some lines or generators are out of service.
Replacement Cost	An estimate of the cost to replace the existing facilities either as currently structured or as redesigned to embrace new technology with facilities that will perform the same functions. This method recognizes the benefits of currently available technology in replacing the system. For example, a number of small generating units may be replaced with a single large unit at lower unit costs and greater efficiency.
Reserve Margin	The difference between net system capability and system maximum load requirements. It is the margin of capability available to provide for scheduled maintenance, emergency outages, system operating requirements, and unforeseen loads. On a regional or national basis, it is the difference between aggregate net system capability of the various systems in the region or nation and the sum of system maximum loads without allowance for time diversity between the loads of the several systems. However, within a region, allowance is made for diversity between peakloads of systems that are operated as a closely coordinated group.
Surplus Energy	Energy generated that is beyond the immediate needs of the producing system.
Surplus Energy	The sale of energy that is projected transaction as excess by the supplier. A sale may take several years to complete and may be interrupted for any reason.

ystem	The physically connected generation, transmission, distribution, and other facilities operated as an integral unit under one control, management, or operating supervision.
'olt	A unit of electromotive force or electric pressure analogous to water pressure in pounds per square inch.
Vatt	The electrical unit of real power or rate of doing work.

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