ELECTRICITY COMPETITION AND FAIR MARKET ACCESS IN CANADA

*Alexander J. Black**

"Every durable bond between human beings is founded in or heightened by some element of competition."—
R.L. Stephenson[1]

I. INTRODUCTION

Canadian electricity generation, transmission, distribution, and marketing industries are restructuring. After decades of provincial and municipal ownership, co-existing alongside some private ownership combined with paternalistic provincial regulation, a competitive momentum is eliciting change. The stewardship of electrical utilities in Canada has shifted in favor of direct access driven by interconnection and convergence. Indeed, the liberalization of United States wholesale and retail electricity markets is causing Canadian regulators and provincial governments to think globally in a fundamental redefinition of the public interest.

This article discusses competition and open access to electricity transmission in Canada. It addresses federal Canadian electricity policy, as it has been hamstrung by the niceties of federal-provincial politics. This article also describes the electricity industry which until recently has been characterized by vertically integrated franchises. Unlike in the United States, there is a relative absence of strong federal regulation concerning inter-provincial and international electricity trade. Nevertheless, the deregulation of the Canadian electricity sector will have an impact on cross-border trade with the United States.

This article contrasts developments in Alberta, Ontario, Québec, and British Columbia. For example, a large stumbling block facing Ontario regulators in the transition to a more competitive environment is "stranded costs." Stranded costs refer to the investments made by regulated utilities, which had duly received regulatory approval, but, in the new order, "are condemned to oblivion by competition."[2] In Ontario, the monopoly electric service providers are owned and funded by the Crown, and their imminent restructuring means that the citizens of the province will ultimately bear those costs. On the other hand, Alberta has investor owned-utilities as well as municipally-owned utilities, with the potential for either customers or shareholders bearing the liability for stranded costs and "stranded value." Yet, all jurisdictions realize that some change is inevitable. The benefits from electricity transmission deregulation in Canada have been estimated as high as \$23 billion (Can.).[3] Accordingly, consumers must incur tran-

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* Alexander J. Black, B.A. (Honors) Lakehead University (1982), LL.B., Dip. Petrol. Law, University of Dundee, Scotland (1984-85), LL.M., University of British Columbia (1988). Member of the Alberta and Ontario Bars. Email: ablack@ucalgary.ca.

1. R.L. Stephenson, cited in RANULPH FIENNES, MIND OVER MATTER: THE EPIC CROSSING OF THE ANTARCTIC CONTINENT 59 (1993).

2. Richard D. Cudahy, *The Folklore of Deregulation (With Apologies to Thurman Arnold)*, 15 YALE J. ON REG. 427, 440 (1998).

3. *Review of Inter-utility Trade in Electricity*, NATIONAL ENERGY BOARD OF CANADA (1994). These

sition costs as the electricity sector in Canada restructures, being spurred on by developments in the United States.

A. The FERC's Extra-Territorial Impact

Regulatory and commercial developments in the United States have had an indirect extra-territorial reach into Canada. The adoption of the Public Utility Regulatory Policies Act of 1978 (PURPA)[4] induced major changes in wholesale power markets, in public policy towards competition, and vertical integration in the industry.[5] A product of President Carter's National Energy Plan, the PURPA encouraged co-generation by requiring that utilities buy electricity from industrial co-generators—qualifying facilities—at "avoided cost." This cost was defined as what a utility would otherwise have had to pay to procure that power. This law helped promote supply from non-utility sources by meeting the demand of utilities without the expense of the construction of new facilities by utilities.[6]

Many states in the United States adopted competitive bidding programs to acquire needed capacity at the lowest possible cost, maintaining that such bids constitute their "avoided cost." Other regulators set the cost through administrative determination or implemented statutory requirements (as implemented in New York). Utilities signed long-term contracts with qualifying facilities, and the Federal Energy Regulatory Commission (FERC) allowed a flat (leveled) rate for the life of the contracts. This led parties to estimate costs of alternate fuels such as oil, for as many as forty years. These estimates proved inaccurate and contributed to high electricity prices, which now result in stranded costs.[7]

In addition, under the Public Utility Holding Company Act of 1935[8] (PUHCA), electric utilities were forced to organize under either a single integrated corporation as a holding company operating predominately in one state (PUHCA-exempt), or as an interstate holding company (PUHCA-registered). The PUHCA subjected registered holding companies to extensive reporting, accounting, financing, and securities-issuance requirements.[9] The PUHCA created an impediment to non-utility generators (NUGs), competing with large utilities.

Under the Energy Policy Act of 1992,[10] Congress created entities known as Exempt Wholesale Generators (EWG), freeing NUGs to operate in many states and with many plants. Transmission also posed a problem. Under the Federal

benefits from diversity sales and long-term firm sales of electricity would require transmission access and the wheeling of electric power.

4. Pub. L. No. 95-617, 92 Stat. 3117 (1978) (current version at 16 U.S.C. §§ 2601-2645 (1994)).

5. Ronald J. Daniels & Michael J. Trebilcock, *The Future of Ontario Hydro: A Review of Structural and regulatory Options*, in ONTARIO HYDRO AT THE MILLENIUM: HAS MONOPOLY'S MOMENT PASSED? 19 (Ronald J. Daniels ed., 1993).

6. Bernard S. Black & Richard J. Pierce, Jr., *The Choice Between Markets and Central Planning in Regulating the U.S. Electricity Industry*, 93 COLUM. L. REV. 1339, 1347-48 (1993).

7. Notice of Proposed Rulemaking, *Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities*, F.E.R.C. STAT. & REGS. ¶ 32,457, 53 Fed. Reg. 9331 (1988).

8. Public Utility Holding Company Act of 1935, 15 U.S.C. § 79 (1994).

9. *See generally*, Jeffrey D. Watkiss & Douglas W. Smith, *The Energy Policy Act of 1992 - A Watershed for Competition in the Wholesale Power Market*, 10 YALE J. ON REG. 447, 465 (1993).

10. Energy Policy Act of 1992, Publ. L. No. 102-486, § 722, 106 Stat. 2776, 2917 (1992).

Power Act, the FERC could not order utilities to provide access to the grid.[11] Furthermore, the PURPA wheeling provision (section 211) proved ineffective.[12] Hence, the provisions in the 1992 Act gave the FERC the authority to issue an order for power to be transmitted over the lines of another utility, as long as the integrity of the transmission system is not impaired and the public interest is served.[13] The legislation distinguishes between the two types of wheeling. Although the FERC has authority to order wholesale wheeling and to set the prices for such transfers, Congress specifically prohibited the FERC from engaging in retailing wheeling. The proscription prevents an EWG from using its open access to transmission lines to serve retail customers.[14]

In Orders Nos. 888 and 889, the FERC found that generic access to utility transmission lines for potential electric suppliers, as opposed to the case by case approach of the Energy Policy Act, was necessary to ensure that the full benefits of generator competition might be realized. Order No. 888[15] addresses open access and stranded cost issues, while Order No. 889 requires utilities to establish an electronic information system and standards of conduct.[16] In 1999, the FERC undertook an initiative on the establishment of Regional Transmission Organizations (RTOs) to ease access to transmission and promote further competition.[17]

Even before Order No. 888, the FERC recognized that stranded costs would be incurred by some utilities as customers used their suppliers' transmission to purchase power elsewhere. Utilities typically built facilities or entered into long-term fuel or purchase power supply contracts with the expectation that their customers would renew their contracts and contribute towards their share of long-term investments and other costs. By offering choice to the customer, the utilities incurred stranded costs. The FERC held that if a utility cannot locate an alternative buyer or somehow mitigate the stranded costs, "the cost must be recovered from either the departing customer or the remaining customers or borne by the utility shareholders."[18] The FERC began using its "transmission access

11. *See, e.g.,* Otter Tail Power Co. v. United States, 410 U.S. 366 (1973) (holding that an electrical power company's refusal to wheel electricity over transmission lines was illegal because the lines are an essential facility).

12. *See generally Southeastern Power Admin. v. Kentucky Utils. Co.,* 26 F.E.R.C. ¶ 61,127 (1984).

13. Energy Policy Act of 1992, Pub. L. No. 102-486, §§ 721-22, 106 Stat. 2776 (1992) (amending §§ 211-212 of the Federal Power Act (FPA)); (current version at 16 U.S.C. § 824j-k (1994)).

14. John F. Lomax Jr., *Future Electric Utility Bankruptcies: Are They on the Horizon and What Can We Learn From Public Service Co. of New Hampshire's Experience?,* 12 BANKR. DEV. J., 535, 543 (1996).

15. *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* F.E.R.C. STAT. & REGS. ¶ 31,036, 61 Fed. Reg. 21,540 (1996).

16. *Open Access Same-time Information System (Formerly Real-Time Information Networks) and Standard of Conduct,* F.E.R.C. STAT. & REGS. ¶ 31,035, 61 Fed. Reg. 21,737 (1996).

17. Notice of Proposed Rulemaking, *Regional Transmission Organizations,* F.E.R.C. STAT. & REGS. ¶ 32,541, 64 Fed. Reg. 31,389 (1999).

18. *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities* (FERC Docket No. RM94-7-001, Mar. 29, 1995) concluded that "we do not believe that the existing supplier's shareholders or its remaining customers should have to bear the costs that were prudently incurred under the old regulatory system to serve the departing customer." William B. Tye & Frank C. Graves, *The Economics of Negative Barriers to Entry: How to Recover Stranded Costs and Achieve Competition on Equal Terms in the Electric Utility Industry,* 37 NAT. RESOURCES J. 175, 195 (1997).

policy as a battering ram to knock down barriers" and expand electricity markets.[19]

B. The Impact on Generation, Transmission, and Distribution in Canada

As a result of competition in the United States, a new breed of independent power producer and trader is competing in the emerging Canadian wholesale electricity market. The Canadian market is directly affected by independent power marketers in the United States, whose sales, boosted by a glut in capacity, rose eight-fold in 1996 to 230 million megawatt-hours (MWh). The price differentials between established and independent power are impressive. Technology makes it possible to produce power at a cost of U.S. $.035 per unit.[20] In contrast, the cost of older technology has forced the monopoly electricity supplier in Ontario to agree to a revenue cap of 3.9 cents per kilowatt-hour (kWh) for four years after the introduction of competition in the year 2000. This figure is somewhat lower than the current cost of generation by established conventional plants, which according to the Independent Power Producers Society of Ontario (IPPSO) is 4.1 cents.[21]

Another boost for independent power comes from the demise of economies of scale which had traditionally encouraged power generation by large, vertically integrated utility companies that also transmitted and distributed power. Beginning in the 1970s, however, additional economies of scale in generation were no longer being achieved. A significant factor was that larger nuclear generation units were found to need relatively greater maintenance and to experience longer downtimes. Smaller generation units became more efficient due to advances in technology and lower fuel costs. Generation ceased to be a natural monopoly. Now, scale economies could be exploited by smaller sized units, thereby allowing smaller new plants to be brought on-line at costs below those of the large plants of the 1970s and earlier. Such new technologies include biomass, combined cycle units, and conventional steam units that use circulating fluidized bed boilers. Although the optimal base load unit size is about 500 megawatts (MW) for coal-fired steam turbines, the optimal size for gas-fired combined-cycle units is about 150 to 200 MW. Indeed, smaller and more efficient gas-fired combined-cycle generation facilities can produce power on the grid at a cost ranging from 5 cents per kWh to less than 3 cents per kWh.[22] This is significantly less than the costs for large plants constructed and installed by utilities over the last decade, which were typically in the range of 4 to 7 cents per kWh for coal plants and 9 to 15 cents for nuclear plants.[23]

19. Joseph T. Kelliher, *Pushing the Envelope: Development of Federal Electric Transmission Access Policy*, 42 AM. U. L. REV. 543, 549 (1993).

20. Bruce Clark, *Power Struggle in the U.S. Energy Sector*, THE FINANCIAL POST, June 6, 1997, at 34.

21. *Stranded Debt Shaping New Ontario Power Market*, ENERGY ANALECTS (ISSN 0315-1654), (Nov. 20, 1998) <http://www.nickles.com>.

22. Wallace E. Brand, *Is Bigger Better? Market Power and Bulk Supply: From FDR to NOPR*, PUB. UTIL. FORT., Feb. 15, 1996, at 23, 25.

23. *Coal and Nuclear Plant Cost Data*, reported in 1994 FERC Form No. 1 and the EIA report, Electric Plant Cost and Power Production Expenses 1991-1993 DOE/EIA-0455(91), for plants placed in service during 1986-94.

II. CANADIAN ELECTRICITY POLICY AND RESTRUCTURINGON THE FEDERAL LEVEL

A. *Jurisdictional Divisions*

Integration of the "Canadian grid" is an idea that stems from the era of Prime Minister John Diefenbaker in the late 1950s and early 1960s. However, efforts toward "co-operative federalism" have been stymied due to the inability of the provinces to agree among themselves.[24] Provincial state-ownership of electricity grids helped to further compartmentalize the industry. Furthermore, the general rules of antitrust law do not apply, since the electricity industry is regulated by a specialized regime.[25]

In a country where natural trade routes are usually north-south to and from the United States, the ownership of the Canadian electricity industry is concentrated, and perhaps compartmentalized, in the ten respective provinces. In *Fulton v. Energy Resources Conservation Board,*[26] the Supreme Court of Canada held that provincial jurisdiction over intraprovincial works and undertakings encompassed jurisdiction with respect to intraprovincial generation and transmission facilities, even though the facilities at issue were to be interconnected with the power system of another province. In this case, the province of Alberta maintained jurisdiction because the facility in question was intended to deliver 99% of its output to local customers within the province, and the interconnection was to enable trade only in "emergency" circumstances.[27]

Conversely, in *TransCanada Power Corp.*,[28] the National Energy Board (NEB) reviewed an application by TransCanada Power Corp (TransCanada). The company applied to the NEB for approval to construct a radial international power line. The proposed line would start near Wild Horse, Alberta, and continue approximately fifteen kilometers into Montana on the Wild Horse Station of the Express oil pipeline. TransAlta Utilities Corporation (TransAlta), a competitor, argued that a condition should be imposed on TransCanada that it first obtain approvals under the Alberta Electric Utilities Act.[29] The issue was the applicability of the Alberta legislation to any such federal undertaking. The NEB exercised its jurisdiction and did not impose a condition requiring TransCanada to file evidence with the board with respect to its compliance with Alberta legislation. In order to impose conditions, a logical nexus has to exist between the subject matter of the application and the subject matter of the condition. The board did not find such a nexus and determined that it would not impose conditions that would subsequently affect the rights of TransCanada.

24. *Inter-utility Trade Review: Inter-utility Co-operation*, NATIONAL ENERGY BOARD 1-12 (1992).

25. *See also* Re: Law Society of Upper Canada and Attorney General of Canada, et al. [1996] 28 O.R.3d 460 (discussing the inapplicability of the Competition Act to a regulated industry).

26. Fulton v. Energy Res. Conservation Bd. [1981] S.C.R. 469 (Can.).

27. P. HOGG, CONSTITUTIONAL LAW OF CANADA, 728 (3d ed. 1992).

28. *In the Matter of TransCanada Power Corp.*, No. EH-1-96 (NEB) (Sept. 24, 1996, Application for an International Power Line, Jan. 1997).

29. Alberta Electric Utilities Act, R.S.A. ch. E-5.5 (1980) (Can.).

B. *Federal Policy for "Fair Market Access"*

Before the amendment of the National Energy Board Act, there were three express criteria for exports, namely surplus, price, and fair market access.[30] Fair Market Access (FMA) is a market-based procedure for the review of natural gas and electricity export applications. Since 1988, the NEB has pursued FMA with more robust results for gas than for electricity, due to structural differences in the respective markets. In 1992 the National Energy Board defined "fair market access"[31] as "meant to afford Canadian purchasers who have demonstrated an intention to buy electricity for consumption in Canada an opportunity to purchase electricity on terms and conditions, including price, as favourable as those offered to an export customer."[32] Essentially, this sort of apples-to-apples comparison gives Canadian purchasers a right-of-first-refusal (ROFR) over Canadian natural resources.

Under the FMA procedure, interested Canadian utilities, brokers, and eligible buyers should have a fair opportunity to purchase Canadian-generated electricity on similar terms and conditions as are made available to export customers. If Canadian buyers are not interested in purchasing electricity intended for long-term exports, the electricity can be deemed to be surplus to Canadian needs.[33] In the 1996 *Intalco Decision*,[34] the NEB discussed the term "eligible Canadian purchaser" and elaborated that in this context Canadian purchasers are those persons with "transmission access and the legal right to effect the transaction" in Canada.[35] While the NEB held that FMA was not limited to utilities with their own domestic service areas,[36] industrial or other customers seeking FMA must file evidence showing that they have transmission access and the legal right to effect the transaction.[37]

C. *Fair Market Access Guidelines*[38]

There are several guidelines provided for FMA.

(1) Export applications may be designated for licensing if Canadians wishing to purchase electricity satisfy the requirements of their own domestic

30. *See, e.g.*, Decision No. EH-3-89, National Energy Board (Aug. 1990).

31. *Inter-Utility Review: Transmission Access and Wheeling*, National Energy Board (1992) [hereinafter *NEB Wheeling Review*].

32. *Id.* at 11.

33. *NEB Proposes A Procedure for Dealing With Crude Oil and Equivalent Export License Applications* (May 28, 1996).

34. *Reasons for Decision, B.C. Power Exchange Corporation*, National Energy Board (Sept. 13, 1996) [hereinafter *Intalco Decision*]. The NEB found that Powerex did not have to provide FMA to a group of British Columbian industrial customers because they "were not able to demonstrate an intention to buy electricity for consumption in Canada because they [did] not have both legal and physical access to effect a purchase." *Id.* at 4.

35. *Id.* at 5.

36. *Intalco Decision*, *supra* note 34, at 5

37. *Id.*

38. Canadian Electricity Policy, Annex 2 (Sept. 1998). These guidelines are applied in NEB Hearings. *See, e.g.*, *The Manitoba Hydro-Electric Board*, No. EH-W-1-92 (NEB) (Aug. 27, 1991, Application for Permits to Export Short-Term Firm Capacity and Energy and Interruptible Energy, Feb. 1993).

service area (as opposed to purchases for resale outside of their own domestic service area) and yet have not been given fair market access to the electricity that the exporter is making available to external markets.[39] However, in the *Intalco Decision*,[40] the NEB suggested that this provision was not necessarily limited to utilities having their own domestic service areas.[41]

(2) Fair market access is a reciprocal concept; it entails certain responsibilities for the Canadian buyer and certain responsibilities for the exporter. In other words, it is not merely a right of first refusal.

(3) Exporters must ensure that potential Canadian buyers are kept informed about the electricity available for sale to external markets. Canadian buyers should be advised of the classes of service available, the quantities available, and the period for which quantities are available;[42] however, while negotiations with export customers are underway, price information may remain privileged.[43] Additionally, the seller's commitment is conditioned on a subsequent lack of Canadian buyers ready to contract at the same terms.

(4) The Canadian buyer must then demonstrate a serious intent to purchase, for example, by informing the exporter of the class of service it is interested in buying and the period of the proposed purchase.

(5) When a Canadian purchaser (i) is interested in buying electricity to satisfy the requirements of *its own domestic service area*, and (ii) has demonstrated a willingness to negotiate the purchase of a class of service that is similar to that being considered by an exporter for sale to an export customer, then the exporter should ensure that the Canadian has an opportunity to negotiate terms and conditions (including price) no less favorable than those being offered to export customers.

D. Permits for the Exportation of Electricity

On April 2, 1997, the NEB issued a *Memorandum of Guidance*.[44] This memorandum interprets the new National Energy Board Electricity Regulations, which became effective on March 19, 1997. This process concerns electricity (export and international powerline) applications at the NEB. The declared purpose of the memorandum is to promote "[f]ull implementation of the September, 1988 Canadian Electricity Policy." Conversely, the 1988 Electricity Policy stems from the Free Trade Deal with the United States, including the elimination of the least-cost alternative test, which is discussed above.

The new regulations are made pursuant to the NEB Act, Criteria for Pro-

39. This provision triggers a full-blown NEB hearing.

40. *Intalco Decision, supra* note 34.

41. *Id.* at 5.

42. This is a fairly easily-discharged obligation, requiring advertisements.

43. Essentially, this is tendering for buyers, describing the service(s) without setting a price. There is an element of paternalism here, because "while negotiations are underway, price information may remain privileged." The NEB has no authority to reveal commercially confidential negotiations and indeed agreements, except insofar as an agreement forms part of an application for an export permit. Transparency of contract terms begins once an agreement is filed as part of an application.

44. *Memorandum of Guidance to Interested Parties Concerning Full Implementation of the September 1988 Canadian Electricity Policy*, File No. 185-A000-19 (revised Aug. 26, 1998).

posed Exports,[45] which describes the substantive criteria for electricity exports. FMA is arguably the most important substantive criteria and is a fundamental aspect of Canadian Electricity Policy. But what constitutes "fair" is an elastic and woolly concept, which is changing to meet new market and regulatory exigencies. Furthermore, the NEB appears reticent to aggressively develop FMA, partly because electrical utilities largely fall under the jurisdiction of the provinces with respect to the operation and maintenance of generating stations.

Nevertheless, a definite trend towards open access in Canadian electricity is being driven by U.S. market developments, including movement towards energy convergence. Section 10 of the NEB Electricity Regulations[46] comprehensively lists "matters that may be included in any permit for the exportation of electricity." These include requirements concerning: (a) the duration of the permit; (b) the maximum quantities of power allowed; (c) the classes of electricity transfers; (d) the maximum duration of export contracts; (e) NEB filings and approval of transfer agreements;[47] (f) the qualification of each class of electricity as firm or interruptible power; (g) the conditions for export curtailment or interruption; (h) the international power lines to be used; (i) the measurement of the power; (j) the changes in circumstance about which a permit holder is obliged to inform the Board; (k) requirements relating to the protection and restoration of the environment; (l) requirements relating to the mitigation of adverse effects of the export on the reliability of the power systems; and (m) requirements relating to the opportunities for Canadians to purchase the electricity proposed to be exported from Canada.

These last two requirements mean that an export permits application must be framed with detailed information. Beside Federal law and policy, the application will concern the law and electricity transmission policy from the Province of proposed electricity generation and export.

E. Requirements of Electricity Export Applications

In order to apply for a permit to export electricity, section 9 of the NEB Electricity Regulations makes various provisions, most of which are unsurprising, such as filing the electricity transfer agreement (i.e. the transmission system that will carry the electricity). Interesting aspects are the need to provide information on: (k) description of U.S. approvals needed and current status; (l) description of Provincial approvals needed and current status; (m) description of review process for each provincial approval; (o) adverse environmental effects from the proposed exports; (p) adverse effects of a proposed export on neighboring provincial power systems; and (q&r) information relating to the opportunities for Canadians to purchase the electricity proposed to be exported from Canada.

A Notice of Application and Directions on Procedure (NOA/DOP) must be

45. National Energy Board Act, Criteria for Proposed Export, R.S.C. ch. N-7, § 119.06 (1998) (Can.).

46. NEB Electricity Regulations, SOR/97-130, Mar. 4, 1997, § 10 [hereinafter NEB Electricity Regulations].

47. "Electricity transfer" means: (a) a sale transfer; (b) an equi-change transfer; (c) an adjustment transfer; (d) a carrier transfer; or (e) a storage transfer.

filed on each utility from which exports are proposed and on directly interconnected utilities. An advertisement must also be made in leading local papers in order to facilitate public comment regarding the proposed exports.

Applications for electricity export permits must include considerable information about relevant provincial approval processes and reviews as well as the impact upon local utilities and neighboring provincial grids. A domino effect will happen once Ontario and Québec open up their electricity grids (in a national exchange for the issuance of the FERC's power marketer's certificate). "Fair Market Access" will become "fairer" once the state-owned monopoly provinces like Ontario loosen their transmission grip. Hence, the NEB will increasingly become involved in electricity export applications whose outcomes will be facilitated by provincial unbundling of services and increased transparency in rates.

F. Electricity Exports, Permits, and Hearings

Public hearings are not normally held for authorization of electricity exports and operation of international power lines. Rather, a permit will normally be issued by the NEB. The policy is designed to avoid duplication of provincial proceedings from which electricity is to be exported, or through which a line is to pass. However, the NEB may recommend to the Governor-in-Council[48] that a public hearing be held for licensing of exports and/or certification of international power lines. A safety valve exists even if the Board issues a permit (i.e. authorization without a public hearing). The Governor-in-Council may revoke a permit and order a public hearing up to forty-five days after the issuance of a permit.

The NEB's discretion whether or not to trigger a public hearing obliges the Board to take a hard look at all considerations that appear to be relevant. Hence, the NEB examines the adequacy of the application. However, initial applications for export permits have been made on the basis of enabling agreements where no specific volumes or prices are granted. Once the open access process matures, applications may prove contentious enough to be remitted to a full-blown hearing.

Besides the NEB's duty as an administrative tribunal, particular considerations apply to exports and international power lines respectively. Permits, when issued, are conditional. They are subject to such terms and conditions respecting any of the matters prescribed in the Electricity Regulations.[49] Certain criteria must be considered by the NEB for Proposed International Power Lines.[50] Aside

48. The Governor-in-Council is the Canadian term for the executive branch of Government. Within the Canadian context, the Prime Minister and Cabinet are sometimes empowered by legislation to make decisions which require the approval of the Governor General who is the viceroy, representing the Queen. The Governor General's approval is perfunctory as the office is largely ceremonial.

49. NEB Electricity Regulations, *supra* note 46, § 10. Thirteen separate requirements are set out. In the case of an applicant seeking waiver of the FMA requirements. *See* NEB Act, R.S.C. ch. N-7, § 119.06(2) (1998) (Can.) (stipulating that the Board "shall have regard to all considerations that appear to it to be relevant" including a list of specifically identified considerations).

50. NEB Act, R.S.C. ch. N-7, § 58.14 (1998) (Can.). This section refers to: (a) the effect of the power line on provinces other than those through which the line is to pass; (b) environmental impact of the construc-

from constructing power lines, "proposed exports" involve the thorny issue of transmission access. The NEB is obliged to consider exigencies that are both affected by and will affect the development of Canadian open access policy and law.[51]

G. Changes in Export Law as a Result of Competition

Annex 905.2 of the *U.S.-Canada Free Trade Agreement* (FTA)[52] required Canada to eliminate the "least-cost alternative test," one of three tests supplied by the NEB for regulating the pricing of electricity exports.[53] Likewise, the North American Free-Trade Agreement (NAFTA) affirms this provision, which promotes stability in trade and an adequate supply of energy products among the three nations.[54] The "least-cost alternative test" provided that export prices "would not result in prices in the [United States] . . . being materially less than the least cost alternative for power and energy at the same location within that country."[55] The NEB applied this test to all energy exports to ensure all costs were recovered, Canadians were not paying more for equivalent service, and the export price was not materially less than the "least-cost alternative" for the purchaser.[56]

Annex 905.2 also states that implementation of the energy chapter would include the administration of any "surplus tests" on the export of any energy goods in a manner consistent with the provisions of Articles 902, 903, and 904. These tests involved procedures to determine how much gas and electricity is surplus to the needs of Canada and the producing province. Surplus tests previously characterized Canadian electricity and gas export policy. The NEB does not scrutinize pricing of gas nor electricity exports, nor does it maintain a surplus test for Canadian needs, since both would arguably violate the FTA.

The provisions of the FTA also reflect those of the General Agreement on Tariffs and Trade (GATT)[57] concerning "national treatment."[58] This provision is

tion and operation of the line (the Electricity Regulations reverentially incorporate obligations under the Canadian Environmental Assessment Act); (c) considerations specified in the Electricity Regulations from time to time. *Id.*

51. NEB Act, R.S.C. ch. N-7, § 119.06 (1998) (Can.). Under this section, the NEB is obliged to consider: "(a) the effect of the exportation of electricity on provinces other than that from which electricity is to be exported; (b) environmental impact of the [export]. . .; (c) whether the applicant has: (i) informed those [potential Canadian consumers] who have declared an interest in buying electricity for consumption in Canada of the quantities and classes of service available for sale, and (ii) [providing 'fair market access' - in other words, whether the applicant has] given an opportunity to purchase electricity on terms and conditions as favourable as the terms and conditions specified in the application to those who, within a reasonable time of being so informed, demonstrate an intention to buy electricity for consumption in Canada; and (d) considerations specified in the [Electricity Regulations from time to time]." *Id.*

52. Free Trade Agreement, Dec. 22, 1987 - Jan. 2, 1988, codified in Canada by the *Canada-United States Free Trade Agreement Implementation Act*, R.S.C. ch. 65 (1988) (Can.).

53. Free Trade Agreement, art. 905, annex 905.2.

54. In accordance with article 603, Annex 608.2(1)(2) of the NAFTA, Canada and the United States agreed to observe exhibits 902.5 and 905.2 of the FTA and the Agreement on an International Energy Program.

55. Free trade Agreement , art. 905, annex 905.2.

56. *The Canada-U.S. Free Trade Agreement,* Department of External Affairs, 31 (1987) (Can.).

57. General Agreement on Tariffs and Trade, Oct. 30, 1947, 61 Stat. A-11, 55 U.N.T.S. 194 [hereinafter GATT] (stating its goals and objectives, including "raising standards of living, ensuring full employment and a

incorporated into NAFTA by virtue of Article 301. National treatment will likely affect trade liberalization in electricity and on regulatory reform within individual jurisdictions. However, "where domestic law mandates a vertically integrated monopoly within a particular jurisdiction," would-be foreign competitors cannot complain of discrimination on the basis of Article III(4) because would-be domestic competitors are equally being denied market access. In other words, "foreigners are being treated as badly as their domestic counterparts, but no worse."[59] The national treatment standard accounts for much of the variation in the pace and extent of regulatory reform, as well as "highly asymmetrical degrees of market access between different jurisdictions."[60] Indeed, "national treatment in the absence of comparable regulatory regimes can cause asymmetrical market access."[61]

In September 1987, the NEB introduced a "market-based procedure" test to determine whether proposed exports are surplus to reasonably foreseeable Canadian requirements.[62] Under this test, the Board may intervene when exports cause Canadians difficulty in meeting their gas (and electricity) requirements at market prices. However, this is difficult to measure, since there are yet no acceptable indices or spot prices for electricity in Canada. The scope for intervention is limited. In fact, one NEB decision was challenged on the basis that it set a minimum export price contrary to FTA Article 902. Along with the market-based procedure, the Board requires applicants for export licenses to file an "Impact Assessment," commenting on whether a proposed export is likely to cause Canadians difficulty in meeting their energy requirements at their market prices.[63]

Since mid-November 1989, the NEB relieved applicants of this responsibility by periodically publishing its own assessment of the impact of an increase in exports of gas. Given the nascent nature of electricity open access in Canada, it seems likely that the NEB will be unable to assess the impact of electricity exports and will seek this information from electricity export license applicants and complainants. In 1994, the federal government and provinces formed an agreement on internal trade[64] with a yet-to-be-concluded energy chapter. Until this

large and steadily growing volume of real income and effective demand, developing the full use of the resources of the world and expanding the production and exchange of goods. . ."). *Id.*

58. Article III (2) of the 1947 GATT requires that "[t]he products of the territory of any contracting party imported into the territory of any other contracting party shall be accorded treatment no less favourable than that accorded to like products of national origin in respect of all laws, regulations and requirements affecting their internal sale, offering for sale, purchase, transportation, distribution, or use." *Id.*

59. Robert House & Gerald Heckman, *The Regulation of Trade in Electricity: A Canadian Perspective*, in ONTARIO HYDRO AT THE MILLENIUM, *supra* note 5, at 128.

60. *Id.*

61. House & Heckman, *supra* note 59, at 132.

62. National Energy Board, Reasons For Decision, Review of Natural Gas Surplus Determination Procedures (July 1987) (Can.).

63. National Energy Board, Reasons for Decision, In the Matter of TransCanada PipeLines Limited, et al., Pub. No. GH-1-89, at 4 (Dec. 1989) (Can.).

64. *Agreement on Internal Trade*, Aug. 23, 1994 (Canada, Internal Trade Secretariat). An earlier agreement dated July 18, 1994, had to be revised to eliminate as many contradictions and inconsistencies as possible without reopening negotiations. It aims for uniform standards and regulations, including the professional serv-

energy chapter is concluded, none of the general trade liberalization provisions of the agreement (Article 1811.3) are to be applied.[65]

III. PROVINCIAL TRANSITION TO COMPETITION

A. *Alberta's Power Pool and Transition to Competition*

Alberta's electric industry structure is the closest that any province in Canada has come to open electricity market competition, despite the need for the resolution of stranded costs and ancillary Power Purchase Agreements (PPAs). In fact, the advent of the Alberta Power Pool actually instigated electricity liberalization in Canada. Subsequently, in April 1997, Ontario Hydro failed in its attempt to obtain unfettered access to the U.S. electricity market when the FERC denied Hydro's revised application for a U.S. "power marketer" license. Ontario Hydro had revised its application by promising to allow U.S. utilities to transmit power on its grid through, but not into, Ontario. Ontario Hydro argued that U.S. utilities did not need access to its grid and to the province since they would be able to sell their energy into a newly-created Ontario power pool. The pool was slated to become the sole buyer of electricity in Ontario and would be required to purchase power from the lowest bidder. Earlier in 1996, however, "TransAlta Corp. won a FERC license after the Alberta government set up a power pool [independent of power producers]."[66]

Alberta has not yet allowed retail access, but has publicly stated that retail access is the ultimate goal of deregulation. The fact that Nova Scotia and Alberta have widespread investor-owned utilities in Canada may account for the latter's willingness to pursue open access. Most of Canada follows the paternalistic practice of relying on provincially-owned, vertically integrated, Crown corporations for electric service. The Provinces of British Columbia and Alberta are part of the Western System Power Pool (WSPP), which includes Washington, Oregon, Nevada, Idaho, Arizona, Utah, Wyoming, California, and parts of Colorado, South Dakota, Nebraska, New Mexico, and Montana. Between 1982 and 1995, generation and transmission costs were pooled and averaged in accordance with the Alberta Electric Energy Marketing Act (EEMA).[67]

This regime was criticized, especially by TransAlta Utilities Corporation, the largest investor-owned utility in Canada, which claimed that the regime was subsidizing expensive generation. The resulting review of EEMA, initiated in 1992, resulted in reforms introduced by the 1995 Electric Utilities Act,[68] which came into effect in 1996. The declared purpose of this reform was to preserve the "Alberta advantage" of competitive electricity prices, which are among the

ices sector. The accord has seven chapters: procurement, investment, labor-mobility consumer related measures and standards, agriculture and food, alcoholic beverages, natural resource processing, energy, communications, transportation and environmental protection. *Labor mobility barriers* come in the form of provincial occupational standards and residency requirements for professional or semi-professional occupations.

65. House & Heckman, *supra* note 59, at 128.

66. Konrad Yakabuski, *Ontario Hydro Denied Greater U.S. Access: FERC wants end to utilities monopoly*, GLOBE & MAIL, Apr. 2, 1997, at B1.

67. Alberta Electric Energy Marketing Act, S.A. ch. E-4.1 (1991) (Can.).

68. Electric Utilities Act, S.A. ch. E-5.5 (1995) (Can.).

lowest in Canada, and to establish a mechanism that guaranteed fair prices from a province-wide perspective.[69]

Since 1996, under the Electric Utilities Act (EUA), the generation, transmission, and distribution of power is separated. The functions of generation, transmission, and distribution are treated separately for accounting, regulatory, and operational purposes. The "Transmission Administrator," an independent body, plans the "grid" for a long-term period. Its duties stem from recommendations in a 1997 report by the Transmission Administrator Advisory Panel (TAAP).[70] The Transmission Administrator, chosen by competitive tendering, is ESBI Alberta, Ltd. This entity is a subsidiary of a major electricity company in Ireland.[71] Hence, the Transmission Administrator is responsible for transmission and setting rates for the six provincial Discos and various generators.

Furthermore, all electrical power produced in the province is now sold into a central and open "power pool." In other words, the Power Pool of Alberta, which accepts power from the generating utilities and sells it to distribution utilities such as Enmax in Calgary, also monitors the electrical supply and demand for the Alberta Interconnected System. Thus, since December 31, 1995, all electricity entering or leaving Alberta's interconnected electric system is exchanged hourly through the power pool. The pool is governed independently rather than by stakeholders. A power pool administrator dispatches all electric generating units according to specific criteria relating to economic merit. This administrator is charged with the financial settlement of electricity exchanged through the pool[72] and is a principal actor in the deregulation/re-regulation process.

Deregulation is surrounded by a kind of folklore which portrays it "as the universal solvent of economic ills . . . a sort of mythology of the market,"[73] but managing the transmission system is not straightforward, given the need to link generators and distributors as well as establish hourly spot prices for power. As a manager, the Independent System Operator is "one of the mythic heroes of deregulation, beholden to no one and capable in theory of monumental feats of coordination and dispatch. He (or it) can guard against the overloading of lines and other threats to reliability. The ISO must also dispatch the power plants so that the cheapest power sources are called on first."[74]

Thus, a mandatory power pool is a short-term electricity market with access for generators, distributors, and consumers. It is a monopsonist which needs a system operator to operate the system without interruption, to provide load balancing services, and to maintain reliability. The system operator must control

69. Leigh Hancher, *Alberta's New Competitive Electricity System*, in *Resources (No. 55)*, CAN. INST. OF RESOURCES L. newsletter, (1996).

70. Transmission Administrator Advisor Panel, *Recommendations and Final Report on the Alberta Transmission Administrator Function*, (Mar. 31, 1999) <http://www.borg.energy.gov.ab.ca/electric/policy/-report1.html.>.

71. *See also* the ESBI Energy Co. homepage. <http://www.esbienergy.com>.

72. Keith F. Miller et al., *Recent Legislative, Regulatory and Environmental: Developments of Interest to Oil and Gas Lawyers*, 34 ALBERTA L. REV. 738 (1996).

73. Cudahy, *supra* note 2, at 427.

74. *Id.* at 434.

operations that were formerly handled by vertically integrated utilities. Generators no longer have fixed franchises or are assigned to specific supply regions but compete for a portion of the demand for electricity. Although distributors and electricity traders provide direct market access to consumers whose total demand is placed within the pool, there remains a need for regulation. For instance, small customers are expected to remain captive customers for a transitional period as long as they do not have access to competing offers, but the pool does not buy or sell electricity. The pool operator creates a spot market by organizing a market clearing price where demand for electricity is offset by price, through a system that evaluates bids.[75] Because demand for electricity is variable and needs an instantaneous response, there will always be differences between what traders can predict and the actual generation required for consumption. Hence, the secondary market has to account for these imbalances.[76]

As part of the new regulatory compact, Alberta Power, Edmonton Power, and TransAlta, the three biggest utilities in the province, retain ownership of their existing high voltage wires. The Government eschewed forcing a divestiture of these assets with the effect of grandfathering existing capacity. The job of the Transmission Administrator is to ensure that all generators and importers can use the wires on a non-discriminatory basis. It sets the tariffs to recover system access costs from distributors and generators, subject to regulatory approval.[77] Each year, the Transmission Administrator prepares a ten-year plan, which is intended to include new assumptions and is a long term economic snapshot on needs of the province. Thus, the Transmission Administrator has the responsibility for long-term planning for transmission (wires) and can compel construction. For example, the Transmission Administrator's decision to compel construction of an open cycle gas turbine generator in Poplar Hills[78] for voltage support and reactive-power to serve Northwest Alberta highlights the trade-off between transmission and generation.

A workable timetable was not achieved until the 1995 Act was amended in 1998 by Bill 27. The amendment was passed by the Legislative Assembly as the Electric Utilities Amendment Act.[79] The 1995 Act required that future generation be de-regulated immediately, whereas the 1998 amending Act provided for full retail choice by 2001. The amending legislation focused on the deregulation of electrical generation from all existing regulated plants. According to the Minister of Energy, Dr. Stephen West, electricity providers "will have to figure out that profits come from keeping customers more satisfied than their competitors can, not from lawyers and consultants winning arguments in front of regu-

75. MASAYUKI YAJIMA, DEREGULATORY REFORMS OF THE ELECTRICITY SUPPLY INDUSTRY 15-17 (1997).

76. SALLY HUNT & GRAHAM SHUTTLEWORTH, COMPETITION AND CHOICE IN ELECTRICITY 26 (1996).

77. *2001-An Electrical Odyssey,* 8 BUS. IN CALGARY 29, 34 (1998).

78. ESBI Alberta Ltd.: Approval of Financial Arrangements for Purchase of Transmission Support Services from CU Power Canada Limited's Poplar Hill Power Plant, Alberta Energy Util Bd. (Decision U98179 (1998).

79. Alberta Dep't. of Energy, "Backgrounder" on the Electric Utilities Amendment Act, 1998 <http://www.energy.gov.ab.ca/electric/restruct/euaa.htm> [hereinafter Backgrounder].

latory boards."[80] By 2001, long-term PPAs are supposed to replace the current price signaling mechanism without requiring a divestiture of generating assets. The purpose of PPAs is to eliminate any market power of the three generating owners.

The amended Electrical Utilities Act provides for a period of transition towards the goal of deregualtion and also provides for the implementation of PPAs. These PPAs will cover most regulated plants from January 1, 2001, until December 31, 2020, with the exception of small plants for isolated communities. Presumably, these PPAs are intended to allow generation owners an opportunity to cover their fixed and variable costs of generation, while transferring the right to bid the output into the Power Pool to intermediaries.[81] Under the new régime, power producers in Alberta offer their output on the basis of competitive bids, circumscribed by "legislative hedges" among generation owners and distributors. These are similar to financial instruments which fix the price of electricity for those who buy out of or sell in the Pool for the volume of energy covered by the hedge. The hedges are intended to reduce the exposure of the parties to the Pool price and ensure that generation owners cover their expected fixed and variable costs.[82]

The PPAs are intended to allow the generation owners a reasonable opportunity to cover their fixed and variable costs of generation while transferring the right to bid the output of the plant into the Power Pool to intermediaries. The intermediaries are expected to be selected through a competitive auction in 2000, and the "Balancing Pool" will be established for the purpose of handling the auction proceeds. The proceeds from the auction will paid into the Balancing Pool (if positive) or paid out of the Balancing Pool (if negative). The net proceeds will subsequently be distributed to or collected from the consumers.[83]

While PPAs between owners of electricity generating plants and marketers of electricity will last up to twenty years, the legal character of the PPA remains to be settled. An Alberta government consultant, the so-called Independent Assessment Team (IAT), issued its report in July 1999, preferring a signed "agreement," considering it to be more attractive to the buyers of electricity. But certain plant owners expressed an unwillingness to enter into any form of contractual relationship with electricity buyers. The IAT concluded that an unsigned "arrangement" is the form required by the EUA, even though some buyers may worry that a future government might seek to vary the terms of the PPA. Because of this perceived problem, the IAT suggested that considerable care be made in drafting these vital auction documents.[84]

These power purchase arrangements are sometimes called Contracts for

80. Hon. Stephen West (Minister, Alberta Department of Energy), Speech, in ELECTRICITY DEREGULATION FORUM 101, 109 (1998).

81. Alberta Energy Utilities Board (EUB), Independent Assessment Team, *Report for July 9th Filing Only*, Alberta Electricity Market Assessment, Proceeding 990277.

82. Alberta EUB, Independent Assessment Team, *July 19, 1999, Report to the EUB Independent Assessment Team, ch. 1. Scope of the Report.*

83. *Id.*

84. Alberta EUB, Independent Assessment Team, *July 19, 1999, Report to the EUB Independent Assessment Team, ch. 3b. Determination of the Form of the Power Purchase Arrangements.*

Differences (CFD), which include cash-settled, over the counter (OTC) options, index-linked warrants, and any transaction which is cash-settled by reference to an uncertain factor in the future (such as the value of an index or a stock price). This term is borrowed from the United Kingdom where these arrangements serve as insurance policies against unexpected increases in electricity costs, and are used to manage price risk to the U.K. Electricity Pool.[85] A CFD is a long-term (one to fourteen years), fixed price contract that specifies an amount of energy and a strike price. Under a two-way CFD, the generator pays to the supplier the difference in price multiplied by the contracted quantity if the pool price is higher than the strike price. If the pool price is lower, then the supplier pays the price difference for the particular quantity to the generator.[86] Another device used in the UK is an Electricity Forward Agreement (EFA). The EFA is a privately negotiated arrangement that is used for trade, commercial, or institutional purposes and is not transacted on a central marketplace or through a clearing mechanism. They are used by parties who can make or take delivery and who often rely on each other's credit without the support of margin.[87]

Such a change in Alberta is to be elicited by an open auction of the contracts which is hoped to diversify the number of sellers into the Power Pool by January 2001. In order to phase-in full retail customer choice by 2001, large industrial customers will be able to choose between competing retailers of electricity and related services in 1999. That option will be extended to all other customers by 2001.[88] The potential dynamics of this system may take the form that is used in California.

> Brokering and trading of electricity commodities, if appropriately implemented through a market such as California's power exchange, could recapture the economies of vertical integration and pooling without giving rise to the transaction costs associated with complex long-term contracts or intra-firm vertical integration. This will rely on efficient pricing mechanisms, such as implementing a PoolCo system along with contracts for differences. Such an approach would allow bilateral negotiations between buyers and sellers, as well as participation in a PoolCo. For example, under this approach buyers and sellers would negotiate a contract for differences, binding the seller to provide power at four cents per kWh. If the PoolCo price is five cents per kWh, the supplier gets five cents from the pool and rebates one cent to the buyer. However, if the PoolCo price is three cents per kWh, the generator gets three cents from the pool and one cent from the buyer.[89]

In the meantime, public concern over re-regulation induced the government to

85. MARK E. HAEDICKE, SWAPS AND OTHER DERIVATIVES IN 1997, CORPORATE LAW AND PRACTICE COURSE HANDBOOK SERIES 571, 577 (1997).

86. YAJIMA, *supra* note 75, at 52-53.

87. Peter Navarro, *A Guidebook and Research Agenda for Restructuring the Electricity Industry*, 16 ENERGY L.J. 347, 364 n. 94 (1995). Also, concerning the United Kingdom (European) see Commission Notice, O.J. C 15/9 (1994) (English and Welsh Electricity Industry) (notices pursuant to Article 19(3) of Regulation 17 informing any interested third parties of the Commission's intention to grant an individual exemption to the notified agreements implementing arrangements for the privatization of the electricity industry in England and Wales, namely (ii) the option contracts or contracts for differences between the fossil-fuel generators and 12 regional electricity companies.

88. Backgrounder, *supra* note 79.

89. Jim Rossi, *The Common Law "Duty To Serve" and Protection of Consumers in an Age of Competitive Retail Public Utility Restructuring*, 51 VAND. L. REV. 1233, 1285 (1998).

include a "stable rate option"[90] in Bill 27. Under that amendment, residential and farm consumers could lock into a rate for up to five years, rather than being faced with shopping around periodically for power in the marketplace.

Since the Alberta government decided to leave the ownership of its three major generators intact, it had to introduce competition in another way, choosing to develop a plan that would let provincial power output be auctioned to marketers who will compete to resell it.[91] Thus, in order to diversify the number of suppliers into the provincial power, the PPAs will be auctioned off after a determination is made on the cost of service to be paid to power plant owners for generation. The intent is that there will be enough suppliers and buyers in the pool to have a market-determined price.[92] If the bids for power exceed the costs of power production, then the surplus will be distributed to customers through a financial balancing pool.[93] Ultimately, the advent of retail competition should result in the concurrent creation of a secondary financial market, complete with a day-ahead forward price, an hour-ahead forward price, and finally a real-time spot price.

B. Stranded Value and System Reliability

The two major players in Alberta differ on how quickly a transition to full deregulation should be accomplished. TransAlta is a widely-held, publicly-listed utility with about 60% of the market. It proposed a three-to-five-year transition period. Conversely, Alberta Power, (a unit of Canadian Utilities, subsidiary of ATCO Limited, the majority of whose shares are privately controlled) wanted a longer time-frame of between fifteen to forty years. The latter's operations are more costly, partly due to the fact that the ATCO unit serves remote areas and also due to the relative newness of its power generation and transmission facilities, which have not been fully depreciated. Conversely, TransAlta's facilities, while older, have been more or less written off over the years, hence its cost base is lower. This has created a dilemma of "stranded value." Unlike Ontario which has an estimated $30 billion (Can.) in stranded costs because of a dysfunctional nuclear program, Alberta utilities are older but very viable. The generating assets in Alberta are valuable and consist mostly of coal-fired plants in the Edmonton region. A compromise was reached to rebate the remaining estimated value, the so-called stranded value, of those plants back to consumers over a twenty-year period.[94] Edmonton Power, with new coal fired units, faced significant stranded cost if the transition period was less than twenty years.

Consistent with the ambit of the new régime is a movement away from centrally planned operations in favor of a more market-oriented approach. However, there remains a need for physical, real time operation of the system which

90. Backgrounder, *supra* note 79.

91. Steven Chase, *The Power Plays of Two Provinces, Fuel for Thought*, GLOBE & MAIL, Jan. 9, 1999, at B1.

92. *Capacity Auction Will Decide Success of Alberta Deregulation*, ENERGY ANALECTS, (Mar. 22, 1999), at 7-8 <http://www.nickles.com>.

93. Electric Utilities Act, S.A. ch. E-5.5, § 45.96 (1995) (Can.) (with amendments in force as of Apr. 30, 1998).

94. *2001*, *supra* note 77, at 34.

requires coordination, coordination which formerly was handled by the generating companies pursuant to joint operating agreements (JOAs). Following a power outage in October 1998, there was much concern expressed by the Transmission Administrator, the government, and the power generators. Part of the reason for the outages is that demand for power in Alberta is growing at the rate of 3% or 300 megawatts per year as the province's economy grows and new residents arrive. As demand creeps close to exceeding supply, the Transmission Administrator, ESBI Alberta, Ltd., estimates that energy rationing between users is likely until the year 2000.[95] Consistent with this view, the local distribution company in Calgary, Enmax, made public its plan for half-hour "Rotating Power Blackouts" in the event of curtailment when the Power Pool asks distribution companies to shed load.[96]

Another reason for potential power outages is that Alberta is an island that is tenuously connected to the North American electricity grid. Although Alberta is at the end of the North American grid, it is a member through the Western System Coordinating Council (WSCC). The WSCC is a Regional Transmission Group (RTG), a voluntary organization of transmission owners, transmission users, and other entities interested in coordinating transmission planning and expansion, operation, and use on a regional and inter-regional basis. Thus, some concern exists that the standards for U.S. cities are different than the standards for service to remote Alberta towns. For example, 11.5 million U.S. customers lost power in two massive blackouts in 1996, when a tree fell on power lines. However, the primary cause of the blackouts was inconsistency in management of the interconnected system. Consequently, the WSCC undertook an active program to implement mandatory system reliability standards. These standards included sanctions beefed up by severe penalties. For instance, if a power system in one jurisdiction is seen as a burden to its neighbor, the troublesome jurisdiction could be cut off from the interconnected grid. The North American Reliability Council (NARC) has similar concerns pertaining to the entire North American grid.

C. *Transmission Tariff Policy*

Under the Alberta postage stamp rate for electricity transmission, consumers of electricity are treated differently than generators. As a matter of policy, Alberta allows consumers to pay one price for transmission, essentially endorsing cross-subsidization of services so as to promote equality within the different geographic regions of the province. Indeed, before the system of "postage stamp rates" was introduced in the 1970s, there were considerable discrepancies between power provider franchises.

Because of increased exceptions to the general use of the "postage stamp rate," the integrity of the "postage stamp" regime is being whittled away. In other words, certain persons are allowed to "bypass" the regime with a consequent impact upon captive users. In December 1998, the Transmission Admin-

95. Steven Chase, *Alberta Energy Crunch Seen Looming*, GLOBE & MAIL, Nov. 3, 1998, at B5.

96. Ian Wilson, *Power Down, Enmax Says Get Ready to Deal with Winter Outages*, CALGARY SUN, Oct. 21, 1998, at 7.

istrator, ESBI Alberta Ltd., said that it was going to propose changes in their Phase 2 Tariff Hearing (which is expected to be filed in May 1999) before the Alberta Energy Utilities Board (AEUB). Part of the concern is that there was no geographic sensitivity in the current tariff. Furthermore, the government of Alberta said that the intent of the legislation follows the "postage stamp" methodology. Hence, the government indicates that the appropriate place to review how transmission charges are allocated is in a "policy review discussion."

Presently, there is no real freedom of choice for power consumers in Alberta, because the prices set by the Power Pool are not, strictly speaking, determined by market forces. Rather, the system has a series of legislated price hedges that protect higher-cost producers from the full force of price competition.[97] Thus, the 1998 amended Act outlines a method by which the current system of price hedges are to be replaced by a system of long-term power arrangements sold by producers to third parties, who would resell the power to industrial or residential consumers. This also implies higher short-term prices, according to a commentator who says that third-party marketers would have to build in some kind of profit margin.[98] However, as competition shifts from wholesale to retail, owners of generating plants will be removed from the trading of electricity. Instead, purchasers will buy power under PPAs and sell the contracts to the Pool, look to resell, or perform other transactions available when the secondary market for electricity develops.

Whether a viable market for electricity develops depends on the effectiveness of the pool and its constituent rules. Unlike bilateral contracting, where trades occur outside the transmission system by traders arranging physical delivery of energy, scheduling with the transmission system operator who then delivers the scheduled power works as follows:[99]

> [T]he pooling approach envisages that sellers will bid to have their product dispatched, buyers will bid to purchase in the system, operator will dispatch the generating units in order of the bids. The price will be set at the highest bid dispatched and each hour, where the lowest man bid. Contracts will be financial instruments "slops" or "contracts for differences", which "substitute" the pool price for a fixed price on terms agreed bilaterally. The system operator neither knows or cares what the contractual arrangements are." . . .The pooling people come mainly from the system operating side and are concerned initially with the physics of getting the system dispatched and how to substitute market signals for the operations which are now done by command control. Pooling market solutions, therefore, derive from the operating solutions. The proponents of a bilateral system, on the other hand, many of whom have had experience in the gas industry, start from the markets which they assert will develop naturally and worry about the operations later.[100]

Owners of regulated generating units, transmission lines, and electric distribution systems are required to prepare a tariff, including rates, for which they must apply to the AEUB for approval.

The transmission administrator is also required to prepare a tariff, including

97. Matthew Ingram, *Still More to Do on Electricity*, GLOBE & MAIL, Sept. 25, 1997, at B2.

98. Matthew Ingram, *Alberta Takes a Leap of Faith*, GLOBE & MAIL, Apr. 28, 1998, at B2.

99. HUNT & SHUTTLEWORTH, *supra* note 76, at 83.

100. *Id.*

rates, for which it must obtain the AEUB's approval.[101] The Act also establishes a negotiated settlement process which permits stakeholders to seek agreement on matters which are within the AEUB's jurisdiction under the Act.[102] Part of the difficulty of the transition to a fully competitive market is a perceived overlap concerning the roles of system planning and the long-term planning of system facilities. However, the transition towards a competitive electricity market is accompanied by consumer fear of price spikes and power outages.

D. Electrical Utilities in Ontario

In 1906, the Ontario Hydroelectric Commission (OHC) was formed to construct and operate a provincial transmission grid which would deliver power from privately-owned hydroelectric generators on the Niagara River to various municipally-owned distribution systems in southwestern Ontario. OHC expanded into a province-wide transmission grid and acquired most of the privately-owned generating facilities in the province, constructing massive new generating facilities of its own. By the 1930s, the essential structure of Ontario Hydro was formed.[103]

Ontario Hydro is the state-owned electrical power producer and was, until April 1999, governed by the Power Corporation Act.[104] It is a Crown corporation, selling 75% of its power to the 312 member utilities of the Municipal Electric Association. These Municipal Electrical Utilities (MEUs) serve all residential customers in organized areas of the province as well as over 750,000 customers directly in unorganized areas of the province. The rates charged by MEUs are subject to the approval of Ontario Hydro,[105] and MEUs face liability if they set rates for end-users which are not approved by Ontario Hydro.[106]

Ontario Hydro is a corporation without share capital, whose Board of Directors is appointed by the provincial government. Some MEUs claim that they are notional owners of Ontario Hydro because of the contributions they have

101. Miller et al., *supra* note 72.

102. Electric Utilities Act, S.A. ch. E-5.5, §§ 31.95, 45.8 (1995) (Can.) (with amendments in force as of Apr. 30, 1998).

103. Daniels & Trebilcock, *supra* note 5, at 1.

104. Power Corporation Act, R.S.O. ch. 18, § 82 (1990) (Can.). The Public Utilities Act governs the duties and powers of municipal and private power utility companies.

105. Power Corporation Act, as amended, R.S.O. ch. 18, § 113(1) (1990) (Can.).

106. Section 118 of the Power Corporation Act expressly provides:

> Where a municipal corporation or a municipal commission receiving electrical power from the Corporation under a contract made with the Corporation under this Act, (a) supplies electrical power to any person upon terms and at rates other than those that have been approved of by the Corporation; (b) grants to any person to whom electrical power is supplied by the municipality or commission, special terms by way of bonus or otherwise as to the rates to be paid for electrical power or as to the terms at which they are to be supplied; (c) neglects or refuses to carry out any direction of the Corporation given under s. 98; (d) by any means whatsoever, directly or indirectly reduces the cost of electrical power to any person so that it is supplied to such person at a lower rate or upon better terms than those approved of by the Corporation; (e) fails to keep accounts in the manner prescribed by the Corporation or makes improper entries therein, or charges against any account items not properly chargeable thereto, such municipal corporation or municipal commission is guilty of an offense.

Power Corporation Act, as amended, R.S.O. ch. 18, § 118 (1990) (Can.).

paid over the years in excess of direct power costs which are reflected on Ontario Hydro's net equity. Conversely, the provincial government has guaranteed all of Hydro's debt which amounted to about $35 billion (Can.), or about 30% of the total provincial public indebtedness, in 1996.[107]

Under the Power Corporation Act, the provincial government, through the Minister of Energy, can issue policy directives, after consultation with the Board of Directors of Ontario Hydro, with which the corporation must comply. The Act also provides for a Memorandum of Understanding between the corporation and the Minister. The memorandum, which must be renewed at least once every three years, sets out the accountability and reporting requirements governing the corporation's relationship with the Minister and the government in matters of government policy that the corporation must respect while conducting its affairs. "The external regulation of Ontario Hydro is *sui generis*, and does not follow conventional modes of regulation in electricity or other utilities."[108]

The MEU's are public, non-profit bodies which take the form of utility corporations, commissions (often handling several sources of human needs such as water, gas, garbage, disposal, sewers, and electricity), hydroelectric commissions, or commissions operated by municipal councils. Municipal councils are given authority to maintain and manage the operation and staff of the utility and to fix and collect rates to pay for supply and installation.[109] This authority is usually delegated to a Public Utilities Commission (PUC).[110]

An MEU is authorized to fix rates to pay for installation and supply of electricity. The corporation is authorized to use discretion[111] as to the rents, rates, or prices to be charged to various classes of consumers. The corporation "may require any consumer to give reasonable security for the payment of the proper charges" for the supply or continuation of the supply of the utility.[112] In *Brantford Public Utilities Commission v. Brantford*,[113] the Ontario Court of Appeal examined the effect of the Savings and Restructuring Act[114] on local utility structure. This legislation is the policy related cornerstone of Ontario's conservative government led by Premier Mike Harris, which fundamentally altered the funding and provision of public services. The city had the power to dissolve the PUC under the Public Utilities Act, and the effect of the Act gave municipalities additional powers to deal with various local boards.

The Supreme Court of Canada in *Nepean*[115] considered how to allocate the cost of power set by Ontario Hydro. Newer municipalities, like Nepean, contributed more heavily to the capital cost of the Hydro system than other municipalities. In 1974, Nepean concluded that the additional charges, resembling in-

107. Daniels & Trebilcock, *supra* note 5, at 2.

108. *Id.* at 3.

109. Public Utilities Act, R.S.O. ch. 15, § 28 (1990) (Can.).

110. *Id.* §§ 38-41.

111. Public Utilities Act, R.S.O. ch. 15, §§ 28(2)-(3).

112. *Id.* § 50(4).

113. Brantford (City) Public Utilities Comm'n v. Brantford (City) [1998] 36 O.R.3d 419 (Ont. Ct. App.).

114. Savings and Restructuring Act, S.O. ch.1(M) (1996) (Can.).

115. Hydro Elec. Comm'n of Township of Nepean v. Ontario Hydro [1982] 132 D.L.R.3d 193, 1 S.C.R. 347 (Can.).

cremental costs for new facilities, had no legal basis. The Supreme Court of Canada agreed, but held that Nepean could not recover the money unlawfully levied by Ontario Hydro on the grounds that Nepean had voluntarily paid them under a mistake of law.[116]

New towns, like Nepean, bore the costs of expansion by being forced to pay a substantially higher toll than the existing tariff. However, the justification for this type of incremental tolling was never made convincingly due to the subjective nature of electricity stewardship by a Crown corporation. Thus, the Ontario Energy Board will address the cost responsibility of electricity toll-making when it assumes its new powers. In other words, incremental tolls arguably shield existing shippers from costs resulting from the new facilities and are based on the premise that existing shippers had some "acquired rights" on the system. For example, the National Energy Board refused to implement incremental tolls simply because some existing users had paid tolls in the past.[117]

In *Kenora Hydro Electric Commission v. Vacationland Dairy Co-operative Ltd.*, the municipal utility mistakenly undercharged supplied electrical power by erroneously using an improper multiplier in calculating the amount due. An action at first instance to recover the amount of the undercharge failed on the ground that the corporation was estopped, since the customer had relied on the charges in pricing its products. The Supreme Court of Canada interpreted the Ontario legislation[118] as precluding the collecting of arrears because the statute did not impose such a clear positive duty as to displace the common law defense of estoppel to a resitutionary claim.[119]

In *Clark v. Peterborough Utilities Commission*,[120] the local public utilities commission adopted a policy of requiring the payment of a cash security deposit equaling two or three month average billing from a residential tenant who could not show "a satisfactory payment history or other reasonable assurance of payment of future charges." Deposits were to be refunded after one year's satisfactory payment history. The policy did not set out any guidelines to interpret "satisfactory payment history" nor about how a customer might "otherwise reasonably assure payment." The requirement that a security deposit be paid was alleged to cause hardship to tenants dependent upon social assistance. The Ontario Court of Justice (General Division) held that the requirement was not contrary to right to life and security of the person;[121] however, the delegation of discretion to employees and staff was improper and *ultra vires*.[122]

116. *Id.* at 219-20, 243.

117. NEB Reasons for Decision, Blackhorse Extension, GH-R-1-92.

118. Public Utilities Act, R.S.O. § 27(2) (1998) (Can.); Power Corporation Act, R.S.O. ch. 423, § 99(d) (1980) (Can.).

119. Kenora (Town) Hydro Elec. Comm'n v. Vacationland Dairy Coop. Ltd. [1994] 110 D.L.R.4th 449 (Can.).

120. Clark v. Peterborough Util. Comm'n [1995] 24 O.R.3d 7 (Ont. Gen. Div.). The appeal of electrical customers was quashed as moot. Clark v. Peterborough Util. Comm'n [1998] 40 O.R.3d 409 (Ont. Ct. App.).

121. Canadian Charter of Rights and Freedoms, § 15.

122. This holding approved several prior decisions. *See, e.g.*, Bridge v. R. [1953] 1 S.C.R. 8 (Can.); R. v. Sandler, [1971] 3 O.R. 614, 21 D.L.R.3d 286 (Ont. Ct. App.).

E. Ontario's Energy Policy

Ontario's energy policy is finally shifting in favor of market forces.[123] The modern context is driven by United States regulatory exigencies and the inefficiency of provincial dirigiste (controlling) stewardship. The latter was illustrated by a public planning mega-hearing that was terminated following the election of the New Democratic Party government (NDP). A 50 to 100% jump in demand for electricity was mistakenly predicted, and Ontario's premier power generator wanted permission to build or expand facilities for hydro, combustion, or nuclear generation. Ontario Hydro abandoned its long-term plan in January 1993, and withdrew its application saying that the provincial recession robbed the province of the growth that had created the need for new facilities.[124]

The Ontario Municipal Electric Association initially opposed retail competition and was cautious about supporting privatization of generating facilities.[125] In August 1996, the Ontario Energy Board (OEB), in its advisory capacity, stated that the surplus of electricity would be gone in three years, assuming that Ontario Hydro's nuclear plants continued to perform poorly.[126] In June 1996, the so-called "MacDonald Report"[127] called for far reaching structural changes. The report recommended alternatives to the state ownership of vertically-integrated Ontario Hydro emphasizing several points: (1) "The status quo is not an option."[128] (2) Fairness, stability, and transparency are touchstones for the new electricity market.[129] (3) To ensure the ongoing operation of a competitive market, a regulatory scheme for electricity must be established.[130] (4) There is an immediate need for a clear policy direction announcement from the government.[131] (5) Many important benefits of enhanced competition in Ontario's electricity system can be captured at an early stage (wholesale competition).[132] (6) Deliberate, but cautious, planning for full retail access as the ultimate end-point for industry restructuring will ensure the continued integrity and stability of Ontario's electricity system.[133] (7) The government should pay particular attention to environmental objectives and to associated opportunities presented by

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123. *See generally* Alexander J. Black, *Independent Power Prospects in Ontario*, PUB. UTIL. FORT., Feb. 15, 1997; and *Environmental Impact Assessment and Energy Exports*, 16 LOY L. A. INT'L & COMP. L.J. 799 (1994).

124. An interlocutory order was the only judicial determination made before Ontario Hydro abandoned the application. Municipal Election Association v. Environmental Assessment Board [1992] 54 O.A.C. 275, 1992 LEXIS 135 (Ont. C.J.).

125. *Restructuring the Electricity Industry in Ontario: Volume 1, Recommended Strategies*, Municipal Electric Association, Sept. 6, 1994.

126. *New IP Opportunities Emerging, Surplus Gone in 3 Years: OEB*, 10 IPPSO FACTO (magazine of the Independent Power Producers) 7 (1996).

127. Donald MacDonald (Chairman), *Report of the Advisory Committee on Competition in Ontario's Electricity System* (June 1996) [hereinafter MacDonald Report].

128. *Id.* at 4.

129. MacDonald Report, *supra* note 127, at 35-36.

130. *Id.* at 97.

131. MacDonald Report, *supra* note 127, at 126-27.

132. *Id.* at 37.

133. MacDonald Report, *supra* note 127, at 39-40.

the process of electricity system reform.[134]

Ontario Hydro appeared to be the only utility in North America allowed to use its monopoly powers to favor its own generation. Consequently, critics, such as the Association of Major Power Consumers in Ontario (AMPCO), said that power contracts in the United States are as much as 40% below Ontario's industrial rates,[135] implying that an urgent need existed for change in the Ontario energy sector.

F. Restructuring in Ontario

Like the United States, the federal government of Canada has exclusive competence over nuclear generating stations, including safety concerns.[136] Operators of nuclear facilities have limited liability and are regulated by the federal government.[137] Canadian courts have barely addressed the ambit or adequacy of emergency plans,[138] except for the decision in *Energy Probe v. Canada.*[139] There, the Ontario Court of Justice (General Division) found no connection between the adequacy of off-site emergency plans, a provincial competence, and the safe operation of nuclear reactors, a federal competence.[140]

The president of Ontario Hydro was forced to resign in August 1997 after a report criticized endemic safety problems within its nuclear division. The problems do not stem from the Canadian-designed Candu reactor, but from mismanagement caused by an alleged nuclear "cult" at Ontario Hydro. With three major nuclear stations (Bruce, Pickering, and Darlington), debt-plagued Ontario Hydro has responded by announcing the shutdown of seven of its nineteen reactors with plans to spend up to $8 billion to resuscitate them and fire up alternative energy sources. Once the building boom for nuclear plants had ended in Ontario, management failed to make the transition into a second stage involving the culture structure and management as well as the rethinking of employee skill mixes and the regulatory process.[141]

One implication is that Hydro-Québec stands to gain a major new export market.[142] Another result is the growth of demand for natural gas following the shutdowns of atomic power generators which have idled 4,375 megawatts of nuclear capacity. Evidence filed with the National Energy Board projects a $1.7

134. *Id.* at 91-92.

135. Arthur Dickinson, *AMPCO Calls Allies of Competition Together*, 10 IPPSO FACTO (magazine of the Independent Power Producers) 7 (1996).

136. Re: Ontario Hydro and Labour Relations Board, et al. [1993] 17 D.L.R.4th 457 (Can.).

137. Atomic Energy Control Act, R.S.C. § 18 (1985) (Can.).

138. For a discussion of similar cases in the United States, see Guard v. NRC, 753 F.2d 1144 (D.C. Cir. 1985) (construing NRC regulation requiring license applicants to provide "reasonable assurance that protective measure can and will be taken in the event of a radiological emergency").

139. Energy Probe v. Canada [1994] 17 O.R.3d 717 (Ont. Gen. Div.).

140. Energy Competition Act, S.O. ch. 15, § 4-25 (1998) (Can.).

141. Paul Waldie et al., *Power Failure: Bunker Mentality*, GLOBE & MAIL, Aug. 16, 1997, at B1 (citing a report by Carl Andognini, an American nuclear expert).

142. Ian Macleod, *Nuclear Flops Benefited Hydro-Quebec*, OTTAWA CITIZEN, Aug. 14, 1997 (citing Tom Adams, a representative of Energy Probe).

billion (Can.) chain of gas-fired power projects.[143]

On November 6, 1997, the Ontario Energy Minister, Jim Wilson, outlined the plans to restructure Ontario's electricity system, including the breakup of Ontario Hydro into three Crown corporations.[144] Effective April 1999, the Ontario Electricity Generation Corporation (OEGC) came into existence and will operate the generation assets now held by Ontario Hydro, being responsible for generating and selling electricity. The other two entities are the Independent Market Operator[145] and the Ontario Electric Services Corporation (OESC),[146] which will run the transmission, distribution, and retail services businesses currently held by Ontario Hydro.[147] The White Paper proposed to:

> 1. Create a competitive market in the year 2000 for both wholesale and retail customers.
>
> 2. Separate monopoly operations from competitive businesses throughout the electricity sector.
>
> 3. Establish an independent market operator (IMO) and provide for an interim supply market for replacement power starting in 1998.
>
> 4. Redesign the Ontario Energy Board and provide it with an expanded mandate to protect electricity consumers and other stakeholders.
>
> 5. Provide the introduction of new mechanisms to ensure environmental protection.
>
> 6. Encourage reform to achieve cost savings in the local distribution sector, including incentive to consolidate some of the existing 306 municipal utilities.
>
> 7. Establish a level playing field on taxes and regulations on electricity market.
>
> 8. Restructure Ontario Hydro into new companies with clear business mandates.
>
> 9. Introduce measures to put electricity companies on sound economic and financial footing.[148]

An independent market design committee, composed of industry and customer representatives, will design the rules of the new electricity market. A major reason for change stems from the poor business performance of Ontario Hydro over the last ten years. Since 1986, electricity prices have grown 54% faster than the Consumer Price Index. When the Ontario marketplace opens, part of the current Ontario Hydro debt will be assigned to the newly created companies. The stranded costs will be paid off by such mechanisms as "pseudo taxes, wires charges, and dividends."[149]

The White Paper acknowledged that Ontario Hydro has been operating far

143. *'Wildcard' in Gas Outlook Looks Like Ace*, 49 OILWEEK, Dec. 21, 1998, at 1.

144. White Paper, *Directions for Change, Charting a Course for Competitive Electricity and Jobs in Ontario*, Nov. 6, 1997.

145. Energy Competition Act, S.O. ch. 15, §§ 4-25 (1998) (Can.).

146. Energy Competition Act, S.O. ch. 15, pt. V (1998) (Can.).

147. Greg Crone, *Ontario Hydro Heads into New Territory*, GLOBE & MAIL, Dec. 31, 1998, at D4.

148. Ontario Minsitry of Energy, Science and Technology, *White Paper Sets Out Plan to Restructure Ontario Hydro*, Nov. 6, 1997.

149. *Id.* at 5.

too long as a monopoly with high electricity prices, excessive debt, and bureaucratic inefficiency. The paper also stated that Ontario Hydro's accountability to the provincial government is ambiguous.[150] Following the 1997 report on Ontario Hydro's nuclear plants, available resources were aimed at improving the performance of the twelve newest nuclear units, "temporarily" laying up the eight oldest reactors. Depending on the results of the nuclear recovery program, a decision will be made whether to invest in the recovery of the older units.[151] Improving management and work habits will take time.[152]

G. Restructuring Legislation

In January 1998, the Ontario Minister of Energy, Science, and Technology established the Market Design Committee to advise on the structure of Ontario's proposed electricity market. The Committee made recommendations on matters that the government should consider regarding legislation for an Independent Market Operator. It also advised on market rules and the powers and responsibilities which any regulatory agency would need to reinforce and support a competitive electricity market.[153] Passed by the Ontario Legislature in October 1998, the new Energy Competition Act (ECA) purports to establish a competitive electricity market by the year 2000 that is intended to ensure a reliable supply of electricity at the lowest possible cost.[154]

In addition to its current role as the regulator of natural gas, the OEB has mandated that utilities in Ontario will be expanded under the Energy Competition Act.[155] The OEB will also act as the independent regulator for the electricity sector. The OEB, overseen by the Ontario Legislature through the Ministry of Energy, Science, and Technology, will focus on strengthening consumer protection. Marketers of energy, both natural gas and electricity, will be required to obtain licenses from the OEB to do business in Ontario.[156] However, Ontario Hydro's residual stranded debt will likely delay the introduction of a true competitive market until after 2000. On October 26, 1998, the Ontario Government accepted the valuation of Ontario Hydro's stranded residual debt at $7.9 billion (Can.). This figure was reached by taking the current debt and liabilities of Ontario Hydro of $39.1 billion and subtracting the value of $15.8 billion (Can.) for Genco, Servco, and the Independent Market Operator and the value of their various dedicated market streams of $15.4 billion (Can.). The government monop-

150. Gayle MacDonald, *Hydro Board: Asleep at the Switch?*, GLOBE & MAIL, Aug. 14, 1997, at B10 (citing David Leighton and Donald Thaim, *Marking Boards Work*, "the bottom line is that there has never been a strong board culture at Hydro").

151. William A. Farlinger (Chairman, Ontario Hydro) *Notes for Remarks to the Institute of Chartered Accountants of Ontario*, at 2 (June 9, 1998).

152. *Id.* at 3.

153. Ontario Market Design Committee (last modified July 27, 1999) <http://www.iemo.com/MDC/-index.html>.

154. Energy Competition Act, 1998, S.O. ch. 15, §§ 1-3 (1998) (Can.) (proposed in Bill 35 (1998), and in force on Royal Assent).

155. Energy Competition Act, 1998, S.O. ch. 15, Schedule B (1998) (Can.).

156. Ontario Ministry of Energy, Science and Technology (visited Aug. 30, 1999) <http://www.est.gov.on.ca/english/en/en_elec_oeb.html>.

oly and the Ontario Market Design Committee agreed to this in a vesting contract which places a revenue cap of 3.9 cents per kilowatt hour for four years after the introduction of competition in the year 2000.[157]

The ECA contains a new Power Corporation Act and a new Ontario Energy Board Act. The OEB will have power to facilitate further deregulation and may streamline regulation for incentive rate-making and may approve utility ownership changes. The Consumer Protection Act will cover energy marketers. The OEB will have the power of licensing small volume gas marketers, and will later license electricity marketers, although it could delegate this authority to a trade association, such as the Ontario Energy Marketers Association (OEMA). The new acts will include a Standard Service Offering for both gas and electricity. If a customer elects not to choose an energy supplier, the utility itself or its affiliate must continue to supply the customer.

H. Québec Open Access

In October 1996, the separatist *Parti Québécois* government of Québec announced its intent to table legislation to allow private producers and other utilities in neighboring provinces to transport energy for export on the Hydro Québec power grid. Independent producers will pay Hydro Québec the cost of transporting electricity on its grid with rates set by a new independent energy board. Although the bill will not allow independents or U.S. utilities to sell directly to retail customers in the province, the government will conduct a six-month study on the implications of electricity deregulation.

A major impetus is the lucrative U.S. market which, under rules set by the FERC, will require Hydro Québec to open its grid to U.S. utilities before it can directly transport its power to customers in the United States. Natural Resources Minister Guy Cheverette said the legislation would "equip Québec with the tools to prepare itself for the coming deregulation of the American electricity market."[158] Under the traditional monopoly, independent power producers were trapped in selling power to the state-owned utility, Hydro Québec, even though they could fetch lower prices in the U.S. market. This will put pressure on Ontario to open its grid, where residential and industrial electricity rates are 30 to 40% higher than in Québec, largely due to Ontario Hydro's heavy reliance on nuclear energy. Indeed, Québec is counting on access to lines in Ontario and New Brunswick in order to export its electricity to states bordering these two provinces in the United States.

Private operators will have exclusive rights to build power stations with a capacity of up to 50 megawatts of electricity, up from the previous threshold of 25 megawatts. Under the new policy, Hydro Québec will remain the sole distributor of electricity in the province, with the exception of nine small municipal utilities that exist. The provincial utility will rely on private producers to meet new demand instead of adding to its own capacity. Signaling an end to large hy-

157. Stranded Debt Shaping New Ontario Power Market, ENERGY ANALECTS, (Nov. 23, 1998) at 3 <http://www.nickels.com>.

158. Konrad Yakabuski, *Quebec to Open Power Grid*, GLOBE & MAIL, Oct. 24, 1996, at B1, B10.

droelectric projects, it is expected that private power will create an additional 600 megawatts during the next fifteen years. The rights to build private power installations will be put to public tender and follow a strict and transparent approval process.

A new Bureau of Energy Efficiency will also be created. Energy saving measures will be created, and their cost will be determined by a new independent energy board which will also have the mandate to review the cross-subsidization of electricity rates. Until now, commercial and industrial users have been charged more in order to keep residential electricity prices low. The energy board will examine the rate Hydro Québec will charge to transport the electricity of private producers and other provincial utilities on its power grid.[159]

In response to FERC Order No. 888, Hydro-Québec has set up a new transmission division (*TransEnergie, une division d'Hydro-Québec*) to give non-discriminatory access to outside suppliers. The Québec utility is changing its position concerning the Churchill Falls hydroelectric project in neighboring Labrador. This project is the world's sixth largest hydroelectric scheme with a current production of more than 5,400 megawatts and potential generating capacity of 8,500 megawatts if two undeveloped sites, Gulf Island and Muskrat Falls, are exploited. Under a 1969 deal with the Government of Newfoundland and Labrador, Hydro-Québec buys almost the entire Churchill Falls output in a sixty-five year agreement where the Québec leviathan sells power at twenty to thirty times higher than cost. According to the Newfoundland government, this means that Hydro-Québec makes about $600 million (Can.) a year from Churchill Falls, whereas Newfoundland makes only $16 million (Can.).

The reason for this improvident deal essentially pertained to Québec's monopolistic control over transmission access. In 1980, the Legislature of Newfoundland attempted to expropriate the fixed assets of Churchill Falls (Labrador) Corp. Ltd. while expressly precluding the company from asserting any claim either for compensation in addition to that provided by the legislation for the loss of its property, or damages for the breach of any of its leases. Subsequently, the Supreme Court of Canada ruled in favor of the French-speaking province.[160]

La Régie de l'énergie du Québec (*La Régie*) is a quasi-judicial body created on June 2, 1997, to economically regulate monopoly electricity suppliers and advance the energy needs of consumers while promoting a secure and environmentally cognizant energy industry.[161] *La Régie* fixes tariffs and conditions of service for electricity, respective purchase contracts, export contracts as well as transmission tariffs, and conditions which are particularly timely as Québec moves forward in the North American deregulation process.

La Régie has the authority to set, in public hearings, the tariffs and condi-

159. Konrad Yakabuski, *Quebec Looks More to Private Sector for Electricity*, GLOBE & MAIL, Nov. 27, 1996, at B5.

160. Bernard Simon, *Canadian Utilities Toe U.S. Regulators' Line: Hydro-Quebec and Ontario Hydro Forced to Either Open Markets or Face Loss of Exports South of the Border*, THE FINANCIAL POST, July 26, 1997, at 4. *See also* Churchill Falls (Labrador) Corp. v. Newfoundland, [1984] 1 S.C.R. 297, 333; 8 D.L.R.4th 1 (Can.).

161. *La Régie de l'énergie du Québec*, (last modified Sept. 1, 1999) <http://www.regie-energie.qc.ca/200/main205.htm>.

tions for electricity generated or transported by Hydro-Québec and can exclude from regulation such special supply contracts as the government may determine. *La Loi sur la Régie de l'énergie* gives Hydro-Québec an exclusive right to distribute electricity in Québec, except for areas served by a private or municipal system.[162] Section 31(2) of the *Loi sur la Régie de l'énergie* provides that *La Régie* has exclusive competence to monitor the operations of Hydro-Québec and to assure itself that consumers are provided for sufficiently and paid according to a just tariff.

I. Newfoundland and Labrador

The Québec Act will make it more appealing for Newfoundland to sell electricity to Québec by developing new hydro-electric sites on Labrador's Lower Churchill River. Under the controversial 1969 Upper Churchill Falls Contract with Hydro-Québec, Newfoundland is locked into onerous terms which it wants to renegotiate. In 1984, the Supreme Court of Canada found that Newfoundland's expropriation of the assets of a corporation situated within its borders was a colorable attempt to interfere with a power contract that gave Hydro-Québec a favorable price on Labrador electricity.[163]

In 1969, the Churchill Falls (Labrador) Corp., a federally-incorporated company, signed a power contract with Hydro-Québec whereby it agreed to supply Hydro-Québec virtually all of the hydroelectric power produced at Churchill Falls for a term of sixty-five years. Delivery of power to Québec began in 1971, but in 1974, the Newfoundland government attempted unsuccessfully to recall more power than was provided for in the power contract. In 1980, the Newfoundland legislature enacted the Upper Churchill Water Rights Reversion Act (the Reversion Act), which provided for the reversion to the province, free and clear of all encumbrances and claims, of the rights water use and the water power rights described in the statutory lease which underpinned the power contract. The Reversion Act purported to repeal the statutory lease and attempted to expropriate the company's fixed assets used in the generation of electric power. The Reversion Act also attempted to limit compensation to creditors and shareholders. On reference to the Newfoundland Court of Appeal, it was held that the Reversion Act was *intra vires* of the Newfoundland legislature. The Supreme Court of Canada upheld the sanctity of the power contract even if its terms may have seemed to be improvident. The pith and substance of the *Newfoundland Act* was found to interfere with the right of Hydro-Québec under the power contract to receive an agreed amount of power at an agreed price. Because the right to the delivery in Québec of Churchill Falls power is situated outside the province of Newfoundland, the attempt by Newfoundland to abrogate the terms of the contract under the Reversion Act was held to be beyond the territorial competence of the Newfoundland legislature.[164]

Talks between Newfoundland and Québec concerning the development of new hydro projects in Labrador were stalled for years. The irritant was Hydro-

162. *LOI SUR LA RÉGIE DE L'ÉNERGIE*, ch. 61 (Project No. 50) (1996).

163. *Churchill Falls*, 1 S.C.R. at 333.

164. *Id.*

Québec's ability to buy electricity from Labrador at a tiny fraction of its resale value. Traditionally, the Québec-owned utility could only sell its electricity at the Canada-United States border, like other Canadian provinces. Wholesale power purchasers in the United States had to make their own arrangements to take delivery, and competing utilities were under no obligation to carry Hydro-Québec's electricity. In order to pave the way for a truly competitive electricity market, the new FERC rules require American utilities to open their transmission grids to competitors at the rates set by regulators. Reciprocally, Hydro-Québec must provide access to its transmission grid to U.S. and Canadian competitors. Essentially, Hydro-Québec has to court Newfoundland, whereas before, Newfoundland was beholden to the utility. Although the contract does not expire until 2041, and Québec is not under any legal obligations to renew it, the FERC developments provide Newfoundland with a powerful bargaining chip.[165]

J. *British Columbia*

Low electricity prices in British Columbia stem partly from the abundance of hydro power realized following the 1961 Columbia River Treaty, which provides an international arrangement between Canada and the United States for the utilization of water resources of both nations. The Kootenay River originates in southeastern British Columbia, flows south and west through Montana and Idaho and back into British Columbia to Kootenay Lake; then it flows southwest to Castlegar, where it joins the Columbia River bound for the United States.[166] British Columbia Hydro and Power Authority (BC Hydro) is the agent of the provincial Crown and the Canadian entity referred to in the Columbia River Treaty. The Canadian and U.S. entities under the Columbia River Treaty are required to cooperate and coordinate the operation of certain dams with the operation of certain hydroelectric facilities.[167]

In 1995, the British Columbia Utilities Commission (BCUC), produced a report called the Electricity Market Review (Review).[168] The current market is dominated by BC Hydro, a publicly owned utility and a private utility, West Kootenay Power Ltd. (WKP), serving about 10% of the province, plus several smaller private and municipal distribution utilities. Utilities in British Columbia, as in many other jurisdictions in North America, file Integrated Resource Plans (IRPs) with the BCUC, a process considering all known resources for meeting the demand for energy services, including alternative sources of supply and energy efficiency, the latter known as demand-side management (DSM).[169]

The report, *inter alia*, rejected retail competition as an option for the British Columbia electricity market and required that owners of generating and trans-

165. Conrad Yakabuski, *U.S. Energy Regulators Push Quebec on Churchill Falls*, GLOBE & MAIL, June 6, 1997, at B6.

166. British Columbia Hydro & Power Auth. v. Cominco Ltd. (B.C.C.A.) [1989] 39 B.C.J. 3 (B.C. Ct. App.).

167. British Columbia Hydro & Power Auth. v. Cominco Ltd. [1985] 1485 B.C.J. 4 (B.C. Ct. App.).

168. BC Electric Market Review, *Executive Summary*, British Columbia Ministry of Employment and Investment (visited Sept 1., 1999) <http://www.ei.gov.bc.ca/policy/reviews/elecmark/1EMREVES.HTM> [hereinafter BC Electric Market Review].

169. BC Electric Market Review, *supra* note 168, *The Current Electricity Market in British Columbia.*

mission assets establish fully separate operating divisions for these, with elimination of cross-subsidies with other divisions of the utility. In the medium term, the report calls for BC Hydro's electric utilities to transfer their generation assets into separate corporate entities. It also calls for a process to determine the appropriate design of entitlement contracts, horizontal de-integration in generation, and an establishment of Wholesale Poolco model.[170]

In September, 1997, the FERC gave BC Hydro final approval to sell power at unregulated rates directly to U.S. customers. BC Hydro was the first Crown-owned power utility in Canada to have that right; another was TransAlta Utilities Corporation based in Calgary. The decision means that BC Hydro's electricity export arm, British Columbia Power Exchange (Powerex), can ship surplus electricity directly to U.S. wholesale customers and buy power in the United States for resale at market-base prices to American clients. Ironically, BC Hydro's industrial customers can still not purchase United States power because of BC Hydro's monopoly. Previously, BC Hydro had to conduct business at the Canada-U.S. border, where it could sell power to the client through a utility or power marketer. Hydro-Québec's application received conditional approval, pending the filing of more information. However, the FERC has rejected Ontario's application for the right to market its power in the United States, because Ontario will not adequately open its transmission network to competitors.[171]

BC Hydro's electricity rates are the third lowest in North America. On March 27, 1998, the British Columbia government froze BC Hydro rates at least through March 31, 2000, and credited the electricity bills of BC Hydro customers with a $31 million dividend. Residential and small industrial customers received a one-time, 2% credit on their bills and large commercial customers a one-time, 1% credit. This is the seventh year in a row that BC Hydro has not increased general electricity rates. In 1995, former BC Hydro President and CEO John Sheehan said that retail competition would occur by 1998. This did not happen, nor have industrial rates dropped as he predicted, and BC Hydro has purposely distanced itself from his assumptions.[172] Thus, these low rates appear to be artificially low.

The BCUC had formerly set BC Hydro's rates using the conventional "just and reasonable" test. The government of British Columbia issued special directions to BC Hydro, and subsequently BC Hydro's customers complained to the BCUC that the utility was generating more revenue than could be supported by these preferential Special Directions. The government then replaced an existing rate cap on BC Hydro rates with a rate freeze, thereby removing all control of BC Hydro's rates from the BCUC.[173] The prospect of job loss were used as lev-

170. BC Electric Market Review, *supra* note 164, *General Recommendations.*

171. Ann Gibbon, *BC Hydro Wins Access to U.S.*, GLOBE & MAIL, Sept. 25, 1997, at B5.

172. The Facts About BC Hydro's Electricity Rates (visited Aug. 30, 1999) <http://eww.bchydro.bc.ca/-html/rate_facts.html>.

173. Utilities Commission Act, R.S.B.C. ch. 473.3 (1996) (Can.).

> (1) The commission must comply with any general or special direction, made by regulation of the Lieutenant Governor in Council, with respect to the exercise of its powers and functions.
>
> (2) The Lieutenant Governor in Council may issue a direction to the commission specifying the factors, criteria and guidelines that the commission must or must not use in regulating and fixing rates

erage to justify the decision which has been reaffirmed by the government. Recently, the Employment and Investment Ministry announced that a confidential discount in electricity prices is being allowed for ski resorts under the province's Power for Jobs, as opposed to troubled British Columbia industries and heavy electricity users such as forestry and mining.[174]

BC Hydro can implement a new wholesale rate in the province without affecting its trading subsidiary's ability to market electricity in the United States. The FERC found that BC Hydro's rate and allocation provisions were a Canadian concern, outside the commission's jurisdiction, and that BC Hydro wants a new two-part transmission rate to raise money to expand congested paths on its domestic transmission system.[175]

Sheenan is suing BC Hydro for wrongful dismissal. Audio tapes of a two-day session with senior management in 1995 are being challenged by the utility on the grounds that they represent the executive's mistaken assumptions on how the electricity market would evolve. In 1995, the utility created the Power Exchange Operation, which it said would act the same as a spot electricity market. Sheehan said during that meeting that industrial rates were as much as 12% higher than they should have been but were kept intentionally high "so that we can save significant costs."[176] These excessively high rates still continue according to Kamloops-based Highland Valley Copper, which needs to reduce its production costs in the face of slumping world copper prices, which are currently around 65.66 cents per pound. According to a spokesman for Highland Valley Copper, a significant part of its production costs are electricity costs (currently 14% of its production cost or about $3 million per month), and this could be set-off if its rates were the same as the rates paid by Washington-based aluminum smelter Intalco Aluminum. According to its spokesman, Mr. Trevor Phelps, "Intalco is paying about 25% less for electricity from BC Hydro than we are paying."[177]

BC Hydro customers, including industrials, are reputed to be the victims of rate gouging. According to Sheenan, BC Hydro gouges its customers by locking them in, and preventing them from purchasing electricity from competing suppliers. When Sheenan made his remarks, there was a surplus of electricity on the West Coast. Intalco entered into a five year firm contract with BC Hydro at rates which were at least 33% less than what British Columbia industrials pay. Commentators say that the government of British Columbia creates a problem by both owning and appointing the regulators of BC Hydro, and that the answer to

for the authority.

(3) The commission must comply with the direction under subsection (2) despite

(a) any other provisions of this Act, or

(b) any previous decision of the commission.

S.B.C. 1980-60-3, 3.1; S.B.C. 1983-10-21, 22; S.B.C. 1989-45-12.

174. Ann Gibbon, *Intrawest to Get Discount on B.C..*, GLOBE & MAIL, Feb. 6, 1999, at B3.

175. *Report on Business*, GLOBE & MAIL, Oct. 15, 1998, at B6.

176. *BC Hydro in Fighting Mood as Sheehan Tapes Emerge*, ENERGY ANALECTS, (Jan. 25, 1999), at 3 <http://www.nickles.com>.

177. *Id.* (citing Trevor Phelps, a spokesman for Highland Valley Copper).

this dilemma is competition and some privatization.[178]

IV. CONCLUSION: PROGNOSIS OR LESSONS FOR CANADA

Although open wholesale transmission access exists *de jure* in Canadian provinces, there is little supply liquidity. There is a need for more capacity in east-to-west provincial interties as well as price discovery in competitive markets. Thus, the power market in Canada is not yet functionally competitive. As the electricity sector moves away from the old paradigm characterized by franchised monopolies with captive ratepayers and towards a networked service for managing electric power trading transactions, the actual power consumed may increasingly come from another province or the United States. However, the public policy dimensions of a restructured marketplace are not yet apparent, such as the effects on the traditional public utility obligation to serve all who demand service.

Consumers and power producers face compelling change. Economics does not guarantee that a deregulated competitive producer will have the same earnings as it would under even the most competent cost-based regulation. Indeed, the restructuring process will have undetermined effects on a competitive producer's margin and how much market share is retained. Furthermore, the restructuring process is heightening the awareness of the costs on which buyers and sellers make market decisions as opposed to the costs on which regulators must base their decisions. Because historical costs bear no necessary relation to today's opportunities, they are irrelevant as guides for economically rational decisions. Market actors look forward, because future costs are the only ones that can be avoided by changing today's decisions. Regulators, on the other hand, look backward, calculating what must be collected today in order to recover past outlays.[179]

Convergence of natural gas and electricity stems from the fully developed energy markets in the United States and Canada. With demand peaking, energy companies are forced to find other outlets for their products if they want to maintain or increase their profit margin. Fiber optic cables on utility easements are one example.[180] The goal of convergence is to increase the range of financial services offered to customers, provide them with services that meet their specific needs, and give them more for their money.

Electricity is slowly becoming a commodity. In 1994, the National Energy Board employed economic modeling when it reported on the probability of enhanced inter-utility cooperation among Canadian utilities and between utilities in Canada and the United States.[181] Assuming that new generation projects started

178. David Austin, *BC Hydro - The Tale of the Tapes, Part 1*, ENERGY ANALECTS, (Jan. 25, 1999), at 6-7 <http://www.nickles.com>.

179. Robert J. Michaels & Arthur S. De Vany, *Market-Based Rates for Interstate Gas Pipelines: The Relevant Market and the Real Market*, 16 ENERGY L.J. 299, 299-300 (1995).

180. *See generally*, Alexander J. Black, *Canada: Commoditization is Not an Ugly Word*, ENERGY ECONOMIST, FINANCIAL TIMES, Nov. 1998, at 205-07, *Co-location and Convergence of Public Utility Easements, NAFTA: Law and Business Review of the Americas*, 5 NAFTA L. & BUS. REV. AM. 292 (1999).

181. National Energy Board, *Review of Inter-utility Trade in Electricity*, Jan. 4, 1994 [hereinafter *NEB Review*].

commercial operation in the year 2000, the report concluded that long-term benefits would total over $23 billion (Can.).[182] The report defines transmission access as "the right or opportunity of electricity generating entities to use transmission facilities owned by others," while wheeling was defined as "the authorized use of the transmission facilities of an intermediate entity by two other entities whose transmission facilities are not directly interconnected, in order to sell, purchase, or exchange electricity between them."[183]

Stewards of Canadian utilities face a vexing question: *how will electricity and gas transportation businesses perform under less regulation and more competition?* Studies show that deregulated industries in the United States and the United Kingdom responded by reducing their costs, lowering their prices almost immediately, introducing new services, reconfiguring old services to better accommodate customer preferences, and deploying new technologies and other innovations. Shareholders have been able to earn adequate rates of return, attributed largely to the greater freedom firms enjoy. However, in the face of deregulation, the responses of firms and other market participants are more dramatic than anyone could have predicted.[184]

Accordingly, the broad movement towards a competitive electricity market in Canada is functionally akin to the process in the United States. However, the changes in Canadian electricity law differ from those south of the 48th Parallel as the new legal rules reflect the distinct Canadian ethos. Stewardship of the electricity sector in Canada is entering a new cycle of accountability with an emphasis on transparency of rates, wheeling, and competition from independent power producers. Increasingly, the NEB and provincial regulators will face compelling challenges in decision-making over the next few years, responding to various interest groups affected by market restructuring.

182. *Id.* (Canadian currency, projected year-2000 dollars).

183. *NEB Review*, *supra* note 181, at 5.

184. Kenneth W. Costello & Robert J. Graniere, *The Outlook for a Restructured US Electric Power Industry: Lessons from Deregulation*, ELECTRICITY J., May 1997, at 82.