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Overview of Electricity Regulation in Canada

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I. Introduction

Canada is a federal state, comprised of ten provinces (and three territories, which are not addressed in this paper). The provinces are given significant jurisdictional responsibility in many key areas by the Canadian Constitution. The Constitution assigns jurisdiction over electricity and natural resources to the provinces, and as a result the Canadian electricity industry is primarily organized along provincial lines. As a consequence of this constitutional reality, as well as the variations in each province's political and physical environments, there are significant differences between the electricity industries of each of the provinces. The key market and regulatory characteristics of Canada's individual provincial electricity industries are discussed below.

II. Regulatory Responsibilities in Canada

A. Federal

In the context of the electricity industry, the federal sphere of responsibility is primarily derived from the constitutional authority over international and inter-provincial trade and commerce. As a result, the construction and operation of international transmission lines as well as the regulation of electricity exports to the United States are matters that fall within the authority of the National Energy Board, a federal regulatory tribunal. Canada's nuclear industry is also federally-regulated; this responsibility fall to the Canadian Nuclear Safety Commission. An additional important area of joint responsibility is that of environmental protection. Responsibility for environmental matters (including the environmental assessment of electricity developments) is shared between the federal and provincial governments; which level of government may be paramount changes with various environmental, regulatory and government funding considerations.

B. Provincial

With the exception of those areas of responsibility that are carved out for the federal government, as discussed above, most matters of electricity industry regulation and policy are addressed at the provincial level. Project developers must also obtain certain key environmental approvals at the provincial level.

As is discussed in detail below, the provinces have each established regulators, licencing authorities and Crown corporations to administer their industries. Alberta has established a fully-competitive wholesale and retail electricity market; Ontario has open access transmission, wholesale and retail markets, but remains heavily regulated; British Columbia and New Brunswick have each completed the separation of their generation and transmission components; the remaining provinces continue to be characterized by vertically-integrated utilities. Most of the provinces have encouraged independent power development, especially for renewables.

C. Municipal

When undertaking a project within a municipality, electricity project developers, like developers of any type of industrial project, will be subject to municipal building codes, zoning, land-use planning requirements, building and other permits.

D. Aboriginal

In a number of specific instances, certain of Canada's aboriginal peoples (or "First Nations") have being granted the right of self-government. In areas where there a treaty has been signed or a land claim has been settled, an electricity developer may be required to seek permits or approvals from a First Nations government entity, or to enter into resource-sharing arrangements. In areas where an aboriginal rights or land claim has been asserted but not resolved, certain duties to consult the relevant First Nation may exist; developers in such areas need to be keenly aware of their legal responsibilities as they proceed with their projects.

III. Alberta

A. Market Structure

1. Only province with fully competitive wholesale/retail markets

The Government of Alberta began a policy review of the Alberta power industry in 1990. Since then, it has passed legislation which effected the transition from a power industry dominated by vertically integrated utilities with monopoly territories to one where customer choice and competition are intended to determine new generation capacity and supply mix, the price of electricity and choice of retail electricity suppliers.

Commencing January 1, 1996, the Electric Utilities Act (the "EUA") enabled significant steps toward competitive markets and investment in the power industry. The Power Pool of Alberta (the "**Power Pool**") was created, which provided a competitive, real-time spot market for electric energy. The provincial transmission grid was opened to allow all eligible persons to trade energy through the Power Pool. The Power Pool is non-discriminatory and open to any generator, marketer, distributor, importer or exporter that satisfies the qualification requirements established under the EUA and the rules and codes of practice of the Power Pool.

As part of the transition process in Alberta, the owners of regulated generating units were allowed to retain ownership of such assets; however, in order to foster competition with the sale of electricity into the Power Pool, power from these regulated units was decoupled from asset ownership. The government of Alberta required various power purchase arrangements from the assets to be made available by auction to qualified bidders. Successful bidders purchased a specific power product and, subject to certain conditions, were able to resell the energy into the marketplace and/or consume the energy directly. New generators, built on a merchant basis, may sell power directly to the market.

Other than energy produced from exempted industrial systems and generators in remote locations not connected to the grid, all power is now sold through the Power Pool. This power is pooled across Alberta's inter-linked grid to meet the total load of all customers on the system.

Three categories of sellers are eligible to offer and sell electricity through the Power Pool: marketers, importers and independent power producers. Marketers are entities trading electricity within Alberta that have registered certain agreements with the Alberta Electric System Operator (the "**AESO**"). Importers purchase energy through inter-provincial ties with Saskatchewan or British Columbia and offer and sell this electricity to the Power Pool.[1] Independent

[1] In addition to the Saskatchewan and British Columbia tie lines, Montana Alberta Tie Ltd. currently has an application before the Alberta Energy and Utilities Board for approval of a 300kw tie line between Alberta and Montana.

power producers include the various owners of non-regulated generating capacity that have been developed in Alberta since 1996 (or the persons entitled to the electricity output from such facilities).

There are also three categories of eligible purchasers who may bid to acquire electricity from the Power Pool: retailers, direct access customers and exporters. Retailers are the group of entities, including the owners of local distribution systems, who sell electricity to end-use consumers. Direct access customers are able to buy their electricity directly through the Power Pool. Exporters purchase energy from the Power Pool and export it via inter-connections with Saskatchewan or British Columbia.

2. Supply Mix

By virtue of the EUA, new generation capacity developed in Alberta after January 1, 1996 has been and will continue to be subject to market forces rather than rate regulation. The electricity produced by all new generation capacity is available to be traded through the Power Pool and is not subject to the traditional rate-making application process conducted by municipal councils or the Alberta Energy and Utilities Board (the "**EUB**").

Currently, thermal sources account for the majority of Alberta's installed generating capacity. Coal-fired plants provide almost 50 per cent of the province's capacity, while natural gas provides about 40 per cent. The remainder is hydro, wind and biomass (energy produced from organic sources such as wood waste, garbage or animal matter).

Wind generation currently constitutes less than 4% of Alberta's existing generation capacity. Wind capacity will increase significantly over the next several years with over 5000 megawatt ("**MW**") of wind power projects currently listed on the AESO's generation interconnection queue. It remains to be seen how much of this wind power will come to fruition due to some transmission capacity limitations.

3. Alberta Interconnected Electric System

The provincial transmission system has been built over the decades by regional utilities. There are four main transmission facility owners in the province: ATCO Electric Ltd., ENMAX Power Corporation, EPCOR Transmission Inc. and AltaLink, L.P., the latter of which owns more than half of Alberta's transmission system and serves 85% of its population. Under the EUA, owners of transmission facilities retain ownership of their respective components of the system, but the transmission system as a whole is managed by the AESO. The system remains a natural monopoly and continues to be regulated, with the AESO being responsible for setting the transmission tariff through applications to the EUB. All entities eligible to trade power through the Power Pool have open access to the grid.

Transmission access will continue to be open to all suppliers and purchasers of power who will pay non-discriminatory tariffs.

B. Regulation

1. Markets and Market Participants

The AESO is an independent system operator established under the EUA and governed by an independent board appointed by the Alberta Minister of Energy. The AESO is responsible for managing and operating the Power Pool in a manner that promotes the fair, efficient and openly competitive exchange of electric energy in Alberta.

The AESO spot market, or pool price, is determined by market forces. The AESO accepts offers to sell power and bids to buy power through its Energy Trading System, which is an internet-based system used to manage electricity market transactions. The AESO then dispatches electricity in accordance with an economic merit order based on the lowest cost offers to supply demand in real time. All energy traded through the Power Pool is financially settled each hour at a single spot market price. Alberta's wholesale market currently consists of approximately 200 participants and about Cdn. $7 billion in annual energy transactions.

The AESO also licenses and regulates market participants through:

- Application Form and Pool Participant Agreement. Prospective market participants must seek AESO approval in order to be licensed as pool participants by (i) submitting an application for participation that sets out the eligibility and financial security of the applicant; and (ii) executing a Pool Participant Agreement.

- Independent System Operator (ISO) Rules. All market participants are required to comply with the EUA and the ISO Rules, being the rules, practices, policies and procedures for the operation and regulation of the market.

- Operating Policies and Procedures (OPPs). The OPPs establish the technical standards, and operating policies and procedures for the safe, reliable and economic operation of the Alberta Interconnected Electricity System.

- Settlement System Code (SSC). The SSC governs the roles, standard practices and processes required for load settlement in the province.

- Ancillary Services Technical Requirements. This document contains the specific technical requirements that must be met by parties offering operating reserves to the AESO.

2. Regulation of Transmission

The AESO is responsible for managing and planning the Alberta Interconnected Electricity System in a safe, reliable and economic manner and ensuring fair and open access to the Alberta Interconnected Electricity System. Independent of any industry affiliations and owning no transmission assets itself, the AESO must contract with transmission facility owners in order to acquire transmission services and provide customers access to the Alberta Interconnected Electricity System.

In fulfilling these duties, the AESO develops operational and long-term transmission expansion plans, short- and long-term load forecasts of customer access requirements and forecasts, operational and long-term system technical requirements to meet customer demand and annual system costs and billing volumes for tariff design.

Essentially, the AESO is responsible for planning the Alberta Interconnected Electricity System so that generators and load have a reasonable opportunity to exchange energy through the AESO. To this end, the AESO forecasts load and generation growth to determine when, where and what type of transmission facilities are required to be built in anticipation of generation development. Once the AESO determines that an upgrade to the transmission system or a new transmission facility is required, an application is made to the EUB for approval of the need for such upgrade or transmission facility. The AESO then chooses one of the existing transmission facility owners to build the upgrade or new transmission facility. A second application is made to the EUB for approval of the upgrade or facility and its location.

Given the demand growth in Alberta, there are some concerns that the AESO is not proceeding quickly enough with new or upgraded transmission facility applications. Thus, private development of transmission lines, not just to connect new generation to the grid, but also to provide merchant open access transmission service, is underway. The application by the Montana Alberta Tie Ltd., to build a merchant line between Montana and Alberta is spurring interest in broader opportunities for possible new transmission providers.

The costs of building, maintaining and operating the transmission system are recovered through the AESO's transmission tariffs, approved by the EUB, which are structured to achieve a fair allocation of costs among stakeholders and to support a competitive market. The transmission tariff is set by an AESO application to the EUB according to the following two-step process:

The Phase I application determines the revenue requirements for the AESO. The EUB decision on this application determines the prudently incurred costs by the AESO necessary to operate and manage the transmission system in Alberta.

The Phase II application determines the allocation of costs between the different classes of customers for the provision of system access service by the AESO. The

EUB decision on the Phase II application determines the rates charged to customers to recover the revenue requirement determined in Phase I.

3. Alberta Energy and Utilities Board

The EUB is an independent, quasi-judicial agency of the Alberta government. Its mandate is to ensure that the discovery, development, and delivery of Alberta's energy resources and utility services take place in a manner that is fair, responsible, and in the public interest.

While the EUB's regulatory role is currently in a state of evolution similar to the industry as a whole, the EUB is currently responsible for:

- issuing environmental and siting approvals for new generation projects;

- ensuring that electric facilities are built, operated, and decommissioned in an efficient and environmentally responsible way;

- regulating transmission additions; and

- investigating and ruling on regulated rate disputes and transmission system access problems, and approving tariffs.

The EUB regulates the electric distribution system to ensure that customers receive safe and reliable service at just and reasonable rates. These rates have two main components: (i) the charges for the energy commodity itself; and (ii) the charges relating to the delivery of the energy to a customer's home. While the energy charges are determined by the spot market price through the Power Pool, the delivery component remains fully regulated. The terms and conditions of service are also approved by the EUB in rate applications to provide guidelines, regulations, and rules for both the utility and customer to adhere to respecting the non-rate aspects of service. The purpose of the terms and conditions of service is to bring guidance and standardization in quality of service and clarity on specific contentious issues. Only Provincial and Federal legislation would supersede any or all portions of the terms and conditions of service.

4. Market Surveillance Administrator (the "**MSA**")

Established by the EUA, the MSA acts as a monitor of Alberta's electricity market. The MSA has a broad mandate to undertake surveillance and investigation in respect of the Alberta market. To discharge its mandate, the MSA must assess whether the conduct of market participants is consistent with the fair, efficient, and openly competitive operation of the market. In particular, the MSA is responsible for:

- monitoring market participants and the overall performance of the market to ensure that there are no anti-competitive activities and that the ISO Rules are appropriate and are working as intended;

•monitoring the conduct of the AESO and other market participants;

•investigating complaints by market participants;

•communicating the results and recommendations from various monitoring activities and providing information to enhance awareness to build knowledge regarding the market; and

• responding to formal complaints, making recommendations regarding revisions to guidelines, procedures and ISO Rules to properly support a fair, efficient, and openly competitive market and to discourage anti-competitive behaviour.

The appropriate conduct of market participants is set out in the EUA and its regulations, the ISO Rules and the guidelines issued by the MSA.

IV. Ontario

A. Market Structure

1. Market Creation and the Successor Corporations to Ontario Hydro

Until 1998, the Ontario electricity sector was dominated by Ontario Hydro, a state-owned company which integrated generation, transmission system planning, and rural and remote distribution functions. Ontario Hydro directly produced over 90 percent of the province's electricity and controlled the balance of supply through non-utility generation ("**NUG**") contracts. Local distribution companies ("**LDCs**") distributed electricity from Ontario Hydro to consumers within an LDC territory, and Ontario Hydro sold electricity directly to Ontario's approximately 100 largest industrial customers, as well as approximately one million rural and remote retail customers.

In the late 1990's Ontario Hydro suffered poor nuclear performance, major cost overruns, and excessive debt. Rates rose by almost 40 percent between 1990 and 1995 alone. As a result, public confidence in Ontario Hydro eroded, and the provincial government deconstructed the company's monopoly with the promulgation of the *Energy Competition Act*, 1998 which included the *Electricity Act*, 1998 and the *Ontario Energy Board Act*, 1998. These latter two statutes constitute the principal electricity legislation in Ontario.

Pursuant to the *Electricity Act*, 1998, Ontario Hydro was separated into five separate companies on April 1, 1999:

•Ontario Power Generation Inc. ("**OPG**"): OPG assumed Ontario Hydro's generation assets and the direct customer, retail, and wholesale operations. The company's shares are held by the Province of Ontario. Although OPG is not required to pay provincial taxes, it is required to make special payments, which help service Ontario Hydro's more than $20 billion plus in stranded debt.

•Hydro One Inc. (“**Hydro One**”): Hydro One inherited the transmission and rural distribution businesses of Ontario Hydro, as well as the obligation to serve remote communities.

•Independent Electricity System Operator (“**IESO**”): The IESO assumed responsibility for administering the electricity markets in Ontario and for directing the operation of Ontario’s transmission grid.

•Ontario Electricity Financial Corporation (“**OEFC**”): The OEFC assumed all other assets and liabilities of Ontario Hydro, including the stranded debt. The OEFC is also responsible for administering the NUG contracts.

•Electrical Safety Authority (“**ESA**”): The ESA is responsible for enacting regulations on a broad range of operational matters relating to “all work and matters used or to be used in the generation, transmission, distribution, retail, or use of electricity in Ontario.”

A fully competitive wholesale and retail market opened on May 1, 2002. Shortly thereafter, however, the provincial government came under considerable political pressure due to volatile electricity prices, and electricity price and distribution rate freezes were enacted in December 2002. These freezes have since been lifted, but some elements of price smoothing and subsidy remain today (as discussed below).

As a result of intervention in the market, merchant generation ceased. A further agency was created, the Ontario Power Authority (“**OPA**”), to act as a credit-worthy counterparty through which new generation can be procured, by means of long-term power purchase or contract-for-differences agreements. The OPA is also responsible for long-term system planning, conservation and demand management and certain aspects of market evolution.

2. Ontario’s Supply Mix and the Hybrid Model of Regulation and Competition

(a) Capacity and Peak Demand

Ontario has an installed capacity of approximately 31,000 MW, with a summer peak demand of approximately 27,000 MW. Ontario has recently been forced to rely on imports during peaks to avoid brownouts and even blackouts.

(b) OPG and Bruce Power Supply

OPG has a generating portfolio of approximately 22,000 MW, including three nuclear facilities, five fossil fuel-based facilities, 64 hydroelectric facilities, and three windpower facilities. OPG’s 10,000 MW of baseload nuclear and hydroelectric facilities are deemed “prescribed assets”, pursuant to the *Electricity Act*, 1998, and the price which OPG receives for output from these assets is regulated (as described below).

One of the OPG nuclear facilities is the Bruce nuclear generating station (the "**Bruce Facility**"), which has eight CANDU reactors. The Bruce Facility has been leased to Bruce Power L.P., a private sector consortium. At present, six of the eight reactors are operating, producing approximately 4,600 MW. Bruce Power L.P., through a related limited partnership, has undertaken a $4.25 billion refurbishment program to return the other two reactors to service, and refurbish two other reactors, which will bring the Bruce Facility's capacity to 6,200 MW. Bruce Power has negotiated an agreement through the Ontario Government whereby the Bruce Facility's refurbishment costs are secured, subject to certain exceptions through a contract with the OPA. The contract provides for a price floor and ceiling, as well as various risk sharing mechanisms.

(c) Non-Utility Generation Contracts

During the 1980s and the 1990s, Ontario Hydro responded to anticipated growth in demand for electricity by contracting with private companies for the construction of NUG facilities. When these contracts were negotiated, Ontario Hydro was forecasting tight supply conditions in the province, and the power prices granted under the contracts significantly exceed the current cost of electricity. Approximately 100 long-term NUG contracts remain in effect, delivering six percent of the province's electricity supply. These contracts are presently administered by OEFC, and will not begin to expire until 2010.

The government has deemed that the above-market price of the NUG contracts should be recovered from Ontario consumers through a surcharge pooled with the Ontario Hydro debt retirement charge.

(d) Independent Power Producers

The balance of supply in Ontario is provided by independent power producers ("**IPPs**", each an "**IPP**"). In the years after Ontario Hydro was split into its constituent portions, seven IPP merchant generation facilities were commissioned. However, the 2002 government intervention in market prices for electricity ended merchant IPP. The OPA was created specifically to procure new privately financed supply, and it has moved rapidly to fulfill its mandate by issuing a series of requests for proposals ("**RFPs**"), which have increased IPP investment in gas-fired, wind, other renewable energy and combined heat and power ("**CHP**") projects. Since 2005, over $10B in new generation or nuclear refurbishment has been contracted for. IPP generation will continue to form a significant part of Ontario's new supply.

To date, most of the contracts that the OPA has signed with IPPs provide either a guaranteed fixed monthly net revenue requirement ("**NRR**") or a fixed price for the power paid to the IPP. Both such arrangements are similar to contracts for differences. For gas-fired and most of the CHP projects, the monthly payments are determined on a deemed dispatch or operational mechanism, whereby the supplier is deemed to operate the plant when the spot price of electricity equals or exceeds the marginal cost of operating the facility. Revenue is imputed to the supplier from such deemed operation, offset against the NRR. If the imputed revenue is less than the NRR, the OPA will pay the difference to the supplier and if the imputed revenue exceeds the NRR, the supplier is required to pay to the OPA most or all of the excess.

The agreements issued by the OPA for wind /renewable energy supply and nuclear refurbishment provide a guaranteed fixed price for the power delivered by the supplier, in some cases up to a cap on the quantity of power (with spot prices paid after such cap is reached). If the spot market price is less than the guaranteed fixed price, the OPA will pay the difference to the supplier and vice versa.

From a trading perspective, the OPA has signed contracts which provide varying degrees of ability for the supplier to sell power outside of the contracted capacity. In simple terms, three types of OPA contacts have been executed:

- Incremental capacity reduction – the supplier may nominate once a year to reduce the capacity commitment, or opt out of the commitment all together. However, the supplier may not revert to a previous commitment level or opt back into the contract.

- One time reduction – the supplier may opt out of all of the contract, at one time. The supplier may not opt back into the contract.

- No reduction – 100% of the capacity is committed throughout the life of the contract. The OPA retains the right to provide specific dispatch orders for all of the contracted power.

- The OPA is presently evaluating several market mechanisms to stimulate liquidity through the use of its procurement power and market function role, such as load serving entities and power auctions.

3. IESO Physical and Financial Markets

The IESO administers both physical markets and financial markets. In terms of physical markets, the IESO operates the real-time wholesale market ("**RTM**") and the market for ancillary services. The IESO may also procure physical output through reliability must-run contracts with generators. Currently, the transmission rights market ("**TRM**") is the only financial market, although the IESO has proposed to implement a day-ahead market ("**DAM**"). A day-ahead commitment process ("**DACP**") has also been implemented in order to enhance system reliability and forward price signals. Under the IESO Market Rules for the Ontario Electricity Market (the "**Market Rules**"), the IESO has authority to implement a capacity market, although no movement has been made toward developing such a market.

There is also a bi-lateral market, and a forward power auction process. Neither of these is administered by the IESO, although the IESO provides the settlement service.

(a) Real-Time Wholesale Market

In the RTM, offers are submitted by generators for each hour of the day and every five minutes. The IESO balances the demand for electricity with the offers from generators and calculates the Market Clearing Price for that five minute dispatch interval. The Market Clearing Price is set for each five-minute interval for (i) energy across Ontario; (ii) energy at each of the intertie zones with markets; (iii) each of the three operating reserve classes across Ontario; and (iv) the ten-minute non-synchronized and 30-minute operating reserves at each of the intertie zones with adjacent markets. The five-minute prices are averaged to determine the Hourly Ontario Energy Price ("**HOEP**").

(b) Ancillary Services

The IESO procures ancillary services through contracts with registered Market Participants who provide such services from registered facilities in accordance with the performance standards articulated in the Market Rules. Contracted ancillary services include: (i) regulation; (ii) voltage control service; and (iii) black-start capability. Generation units with automatic generation control capacity provide the regulation service which allows the total system generation to match the total system load minute by minute. Voltage control services involve the control and maintenance of prescribed voltages at specific locations, using defined reactive capacity, energy and manoeuvrability to support system operations. These services are provided by generation units and/or synchronous condensers, capacitors, and other electrostatic equipment of transmitters. Black-start capability involves generation facilities that can be started without an outside electrical supply.

(c) Reliability Must-Run Contracts

The IESO has authority to execute Reliability Must Run ("**RMR**") contracts with a generator, dispatchable load facility, or boundary entity. The supplier or "resource" must have the ability to provide a specified quantity of electricity when called upon by the IESO in order to maintain reliability of the electricity system. Under RMR contracts, the IESO may direct the RMR resource to operate in specific ways when needed. Any costs which the IESO incurs for RMR contracts are recovered from Market Participants as part of the IESO settlement process.

(d) Transmission Rights Market

The TRM allows a Market Participant to sell and to purchase transmission rights associated with transactions between the IESO-administered Market and an adjoining electricity jurisdiction. The TRM allows Market Participants who import and export power to buy financial protection ahead of time that hedges their prices for power across interties. The IESO conducts auctions for transmission rights which are financial instruments that entitle a holder to a settlement amount based on the difference between energy prices in two different zones. The IESO determines which bids and offers are successful given the clearing price for each transmission rights auction.

(e) Day Ahead Commitment Process

The IESO has instituted the Day-Ahead Commitment Process ("**DACP**") in order to enhance the reliability of Ontario's electricity system. The DACP allows domestic suppliers and dispatchable loads to submit offers and bids one day in advance, and generators are able to signal in advance any limits on their production for a given dispatch day. In this way, the DACP is intended to improve information regarding the operation of the market so as to allow the IESO and Market Participants to better gauge the adequacy of market resources. In addition, the DACP helps to improve forecasts of next-day market prices.

The DACP was launched on June 1, 2006, and at is November, 2006 meeting, the IESO Board approved its continuation until such time as another program is implemented providing at least equivalent reliability benefits.

(f) Operating Reserve Market

The IESO also facilitates an operating reserve ("**OR**") market. OR describes capacity which remains in a stand-by status in the event that reserve power is required to accommodate any events of system instability. The OR market was established to efficiently purchase OR from market participants and subsequently activate it, when needed, to quickly restore the balance between supply and demand. Market participants can offer OR to the IESO-administered markets at the same time that they bid or offer energy (to offer operating reserve, there must be an energy bid or offer of at least as many megawatts). The price for OR is set by the IESO every five minutes, based on the offers in the market.

(g) Energy Forward Market (Day Ahead Market)

A report on Ontario's electricity sector by the Electricity Conservation and Supply Task Force in January 2004 recommended that the IESO should develop an energy forward market ("**EFM**"), also known as a day ahead market. An EFM is a financial, non-delivery market, settled on an hourly basis. It is presently under development in Ontario.

In the EFM, a Market Participant may commit to pay or to receive a settlement amount for each settlement hour based on the difference between the HOEP in the RTM and the price established for that hour in the EFM. According to current plans for the EFM, Market Participants would submit offers and bids in the EFM to the IESO. The IESO would conduct an auction for each real-time market dispatch day and would determine which energy market quantities cleared for each Market Participant. The IESO would then establish settlements amounts for each Market Participant pursuant to settlement procedures contained in the market.

4. Transmission and Distribution

Hydro One Networks, Inc. ("**Hydro One**") is the owner and operator of 97% of the transmission assets in Ontario; it is a wholly-owned subsidiary of Hydro One, Inc., which is in turn a Crown corporation, wholly owned by the province. Hydro One also operates a significant distribution business. It is the largest local distribution company ("**LDC**") in Ontario, and serves approximately 1.2 million customers, primarily in the province's rural areas. The remaining LDCs are mainly owned by municipalities. Transmitters and distributors are licenced by the Ontario Energy Board ("**OEB**"), and are subject to rate regulation by the OEB on a cost-of-service basis.

B. Regulation

1. Policy Setting and Regulation

Two entities set electricity policy and regulate the market: the Government of Ontario and the Ontario Energy Board ("**OEB**" or the "**Board**").

(a) Government of Ontario

The Ontario Cabinet retains legislative authority to set policy for Ontario's energy sector and to alter the mandate of any of the Ontario Hydro successor corporations; however, day-to-day oversight of Ontario's electricity and natural gas industries is maintained by the Minister of Energy (the "**Minister**"). Upon the approval of Cabinet, the Minister can issue policy directives to the OEB, the IESO, and the Ontario Power Authority ("**OPA**"), and each is required to implement such policy directives. The Minister can also request that the OEB examine and advise upon any issue with respect to Ontario's energy sector.

(b) Ontario Energy Board

The OEB acts as the regulator of Ontario's electricity and natural gas industries. Although the OEB reports to the Minister, it operates as an independent entity. OEB responsibilities include (a) determining the rates charged for regulated services in the electricity and the natural gas sectors; (b) approving the construction of new transmission and distribution facilities; (c) approving natural gas franchise agreements; (d) formulating rules to govern the conduct of participants in the electricity and the natural gas sectors; (e) engaging in advocacy on behalf of consumers in the electricity and the natural gas sectors; (f) hearing appeals from decisions made by the IESO; (g) monitoring and approving the IESO's budget and fees; and (i) monitoring electricity markets and reporting thereupon to the Minister.

The Board also operates as an administrative tribunal with exclusive jurisdiction "in all cases and in respect of all matters in which jurisdiction is conferred on it." In exercising this exclusive jurisdiction, the OEB is entitled to hear and to determine all questions of law and fact, and may render a decision by issuing an order (except in respect of an application for the designation of a gas storage area, on which the Board can only issue a recommendation to the Government). An order of the OEB may be appealed to Ontario's Divisional Court, but appeals may only be made on narrow grounds – namely, on jurisdiction or on questions of law.

2. Market Administration and Evolution

Two entities administer the electricity markets, and are responsible for market evolution and design: the IESO and the OPA.

(a) Independent Electricity System Operator

The IESO is responsible for administering the electricity markets in Ontario and for directing the operation of Ontario's transmission grid. It is governed by an independent board of directors. The directors are appointed by the Government of Ontario, and regulations made pursuant to the *Electricity Act*, 1998 require that a director not hold any material interest in any entity participating in the IESO-administered market.

Under the *Electricity Act*, 1998, the IESO is given authority to establish rules governing the market for electricity and ancillary services in Ontario (the "**Market**"). Accordingly, the IESO has issued the Market Rules. The IESO is required to administer the Market in accordance with the Market Rules, and all participants in the Market (each a "**Market Participant**") are required to comply with the Market Rules.

The IESO Board has established two panels, the Technical Panel and the Dispute Resolution Panel. The Technical Panel consists of at least eleven representatives drawn from the IESO, Market Participants, and consumer groups, and is responsible for reviewing the Market Rules and for proposing amendments thereto. The Technical Panel may provide clarifications to the IESO as to the interpretation, application, or implementation of the Market Rules. The Dispute Resolution Panel consists of at least ten representatives who are independent of the IESO and who have no material interest in any

Market Participant. The Dispute Resolution Panel is responsible for mediating and arbitrating disputes regarding the application of the Market Rules.

The IESO has established processes by which consumers, distributors, generators, transmitters, and other parties that have an interest in Ontario's electricity sector may provide advice and recommendations to the IESO. For example, the IESO periodically initiates issue-specific stakeholder consultations through the publication of draft stakeholder consultation plans, which set out the issues, the policy considerations, and the process for the consultation. The IESO currently has several issue-specific stakeholder consultations currently underway on topics ranging from the integration of wind power to the IESO's 2007-2009 Business Plan.

The IESO Board has also created the Stakeholder Advisory Committee ("**SAC**", or the "**Committee**"), to provide ongoing interaction between the IESO and various stakeholder representatives on market development and on planning decisions.

(b) Ontario Power Authority

The OPA was created pursuant to the *Electricity Restructuring Act, 2004,* in response to both the reluctance of investors to assume merchant risk and the need for long-term system development. It is a not-for-profit corporation primarily responsible for forecasting medium- and long-term demand for and reliability of electricity resources; for planning adequate generation, demand management, conservation, and transmission for Ontario; for developing the 20-year integrated power system plan ("**IPSP**") for the province (as described below); and in the absence of a robust market that can support merchant generator investment, for procuring new generation through various forms of procurement processes. Since 2005, the OPA has procured or assumed responsibility for over $10 billion in new generation investment.

The OPA is required by the *Electricity Act*, 1998 to develop and to submit an integrated power system plan ("**IPSP**") to the OEB. The Minister issued a directive to OPA in May, 2005, that it commence development of the first 20-year IPSP. In addition to addressing overall supply needs, the Minister specified certain additional objectives, such as the implementation of conservation efforts, greater use of alternative and renewable energy sources, and the replacement of coal-fired generation. On August 29, 2007, the OPA filed its IPSP with the OEB after two years of development. The IPSP is largely characterized by the Minister's objectives referred to above, as well as the additional objectives of restoring nuclear capability for baseload capacity through either refurbishment or new build, and of developing transmission in order to enhance reliability and to facilitate planned generation projects.

The IPSP forecasts that approximately $60 billion will be invested between 2007 and 2025 in order to implement the various projects envisioned by the plan. An expected supply shortage by 2012 will drive significant investment in the next three to four years. The OEB's review of the IPSP is expected to begin in late 2007 or early 2008 and to require up to a year for completion, including a quasi-judicial proceeding.

The OPA's legislated objective is to become a procuring entity of last resort. Thus, the OPA is actively working on various programs to facilitate merchant investment in generation, such as fostering market liquidity through such initiatives as its Load Serving Entity project, and its forward power auctions.

3. Market Rules Enforcement and Market Surveillance

Market Rules enforcement is performed by both the IESO and the OEB. The IESO has general oversight for ensuring that Market Participants abide by the Market Rules, and this responsibility is vested in the Market Assessment and Compliance Division ("**MACD**"). The MACD is required to investigate alleged breaches of the Market Rules and, where necessary, to issue letters of non-compliance, to impose financial penalties, or to pursue other sanctions against non-compliant Market Participants. The IESO can issue fines of up to $10,000 for a breach of the Market Rules.

In addition, where a Market Participant engages in an activity that requires a licence from the OEB, the Market Participant is required by the terms of its licence to abide by the Market Rules. Under the *Ontario Energy Board Act*, 1998, any person or entity that fails to comply with a condition of a licence is guilty of an offence. As such, if a Market Participant operating under an OEB licence breaches the Market Rules, the OEB can impose a fine of not more than $250,000 on a corporation and $50,000 on an individual for a first offence and of not more than $1,000,000 on a corporation and $150,000 on an individual for any subsequent offence.

Market surveillance, meanwhile, is performed by the Market Surveillance Panel ("**MSP**"), a division of the OEB, which monitors, investigates, and reports on activities and behaviour in the Market. The MSP is also responsible for investigating, and making recommendations on, the activities and behaviours of specific Market Participants, if they are suspected of gaming or abusing market power; the design of the Market Rules and other operating procedures maintained by the IESO; and the structure of the Market. The MSP relies on the IESO's Market Assessment Unit to monitor the market on a daily basis to identify inappropriate or anomalous conduct by Market Participants and any other activities having an adverse effect on market efficiency.

V. Québec

A. MARKET STRUCTURE

1. Hydro-Québec

Québec is served principally by Hydro-Québec, a government-owned monopoly with major cost-competitive hydroelectric resources, including significant storage. Under the *Hydro-Québec Act,* Hydro-Québec's objectives are to supply power and to pursue endeavours in energy-related research and promotion, energy conversion and conservation, and any field connected with or related to power or energy. Hydro-Québec operates one of the two largest systems in Canada for the generation and distribution of electric power and supplies virtually all electric power distributed in Québec.

Hydro-Québec’s operations are allocated among five business segments, which include:

•Generation: Hydro-Québec Production operates and develops Hydro-Québec’s generation facilities in Québec. It guarantees the supply of heritage pool electricity to the Québec market and it participates in the Québec wholesale market by responding to calls for tenders from Hydro-Québec Distribution. It sells electricity on wholesale markets outside Québec and engages in energy trading activities (“**HQ Production**”).

•Distribution: The primary responsibility of Hydro-Québec Distribution is to supply Québec customers with electricity. To fulfill this responsibility, the division purchases up to 165 TWh/year of heritage pool electricity from Hydro-Québec Production, at a regulated average fixed price of 2.79 cents per kWh. Beyond this volume, Hydro-Québec Distribution must supply Québec customers by issuing calls for tenders from suppliers in the market (“**HQ Distribution**”).

•Transmission: TransEnergy develops and operates Hydro-Québec’s transmission system in Québec (“**TransEnergy**”).

2. Open Access Transmission

Most of Hydro-Québec’s generation stations are located at substantial distances from consumer centers. As a result, Hydro-Québec’s power transmission system is one of the most extensive and comprehensive in North America, comprising more than 20,000 miles of lines.

In May 1997, Hydro-Québec opened access to Hydro-Québec’s transmission grid in accordance with the Hydro-Québec Open Access Transmission Tariff. Consequently, electricity distributors, producers and marketers in and outside Québec can enter into transactions with distributors and producers located outside Québec to buy or sell electricity and to wheel in, wheel out or wheel through TransEnergy’s transmission lines at specified rates. The capacity available on the system is posted on the OASIS (Open Access Same-Time Information System) website.

TransEnergy oversees the optimization of energy resources, power flow and system security. The transmission system is linked with other major power systems in Canada and the Northeastern United States. TransEnergy also provides transmission of electricity to supply local distribution, point-to-point transmission service and connections of privately-owned generation facilities, including Cedars Rapids Transmission Company, Limited, which operates the interconnection between Hydro-Québec's Les Cèdres plant and the Cornwall Electric load in Ontario, as well as the National Grid network in the U.S.

3. Quebec's Energy Policy

(a) Strategy

In May 2006, the Québec government unveiled its latest energy strategy, which defines the Province's goals and plan of action in relation to energy issues for the next 10 years. The development of hydroelectric power is at the heart of Québec's energy strategy. The government plans to create a portfolio of projects totalling no less than 4,500 MW to be initiated within the next 4 to 5 years. The pace of development will therefore surpass the pace set in the previous 15 years. These projects are estimated to necessitate $25 billion in investment over the next 10 years. With this additional 4,500 MW of electricity, the government expects that the long-term demand of the Québec market will be satisfied, industrial production will be stimulated and Québec will be able to export electricity to neighbouring Provinces and States. Hydro-Québec has also announced that it will build a $400 million transmission line to Ontario. The construction of the 1,250 MW line has been given regulatory approval.

(b) IPP Opportunities in Hydroelectricity

The new energy strategy ends Québec's moratorium on small, privately-owned hydroelectric power stations (50 MW or less). However, no target block of electricity from small hydroelectricity generating stations has been provided for in the new energy strategy. Moreover, only projects which are supported and developed by local communities will be authorized by the government. As a result, private developers will be required to partner with local communities in order to develop. In all cases, an agreement with Hydro-Québec on the price of the electricity produced will be required before a project can obtain government approval.

To meet the Province's increasing demand, HQ Distribution has initiated a system of competitive bidding. HQ Production is allowed to bid alongside private producers, subject to a code of ethics overseen by a regulatory body named the Régie de l'énergie (the "**Régie**"). Supply contracts are awarded on the basis of the lowest tendered price and factors such as applicable transmission costs. Final contracts require the approval of the Régie. However, as discussed below, HQ's Production will not be bidding on the new wind energy requests for proposals.

(c) IPP Opportunities in Wind Energy

Two significant calls for tenders (1,000 MW previously awarded and 2,000 MW for which the bids were submitted in September 2007) have already occurred. A third call for tenders relating to 500 MW of wind power will also proceed. This new capacity will increase the production of wind power in Québec to a total of 4,000 MW of installed capacity by 2015, which represents approximately 10% of the total peak demand. The energy strategy confirms that Hydro-Québec Production will not participate as a bidder in the ongoing 2,000 MW call for tenders or in the new 500 MW call for tenders, so as to encourage competition and the confidence of the private sector.

The 500 MW call for tenders is expected to be split into two separate blocks of 250 MW each, one earmarked for Québec's regions and the other earmarked for First Nations communities, in both cases in partnership with the private sector. In order to encourage the participation of small communities and to guarantee them a portion of the $700 million to $750 million of investments related to this call for tenders, individual projects will be limited to 25 MW each.

In the longer term, additional calls for tenders will follow at the rate of 100 MW of wind power for each 1,000 MW of additional hydroelectric power developed by Hydro-Québec.

As an example, the 2000 MW tender RFP is estimated to be worth $5 billion in investment in Québec. However, there are difficult hurdles for bidders. The tender document provides that a minimum of 60% of the total cost of each wind farm must be incurred in Québec. This total cost consists of: (i) the project's developmental costs; (ii) the cost of the wind turbines; and (iii) the total costs of construction. There are additional regional requirements as well.

Québec municipalities have been specifically enabled to be involved in the development of energy projects in concert with private-sector enterprises. Bill 134 provides for a new form of limited partnership, whereby a local municipality or regional county municipality ("**RCM**") could enter into a limited partnership with a private-sector enterprise for the production of wind energy. However, there are financial and liability limits on the municipal involvement.

B. REGULATION

The Régie is Québec’s regulatory authority with primary jurisdiction over the economic regulation of the electricity sector. The Régie fixes and modifies rates and conditions for the transmission and distribution of electricity.

1. Régie de l’énergie

Certain aspects of Hydro-Québec's activities and those of natural gas distributors in Québec are subject to the jurisdiction of the Régie, which was established by the Act respecting the Régie de l'énergie (the “**Energy Board Act**”). The Régie consists of seven members appointed by the Government and is charged with reconciling the public interest, consumer protection and the fair treatment of the electric power carrier and of distributors. The *Energy Board Act* was amended in December 2006 to grant the Régie new powers regarding energy efficiency programs and actions as well as mandatory reliability standards. Under the *Energy Board Act*, Hydro-Québec has been granted exclusive rights for the distribution of electric power throughout Québec, excluding the territories served by distributors operating a municipal or private electric system as of May 13, 1997. The Régie has the authority to:

- fix or modify, after holding public hearings, Hydro-Québec's rates and conditions for the transmission and distribution of electric power;

- approve Hydro-Québec's electric power supply plan;

- designate a reliability coordinator for Québec and adopt the standards of reliability proposed by the designated reliability coordinator;

- authorize Hydro-Québec’s transmission and distribution investment projects;

- approve Hydro-Québec’s distribution commercial programs; and

- rule upon complaints from customers concerning rates or service.

The Régie's jurisdiction does not extend to generation but Hydro-Québec is required to supply heritage pool electricity, as discussed above. Electricity required to meet Québec's needs in excess of the heritage pool electricity must be purchased through a competitive bidding process. Purchase contracts for electricity in excess of the heritage pool are subject to the approval of the Régie. Energy generated in excess of the heritage pool electricity may be sold on the market at market-based rates. Purchase and sales transactions outside Québec are unregulated under the *Energy Board Act*. Transmission rates and service terms and conditions are subject to approval by the Régie.

2. Exportation

The exportation of electricity is regulated in the Province of Québec by An Act respecting the exportation of electric power, which prohibits the exportation of electric power from the Province of Québec without an authorization from the Government of Québec to that effect.

3. Environmental Regulation

Hydro-Québec's activities are subject to federal and provincial environmental laws and regulations, and, to some extent, municipal by-laws.

4. Authorizations Specific to Wind Farms

Certain authorizations are required by provincial and municipal authorities to operate a wind farm facility in the Province of Québec, including, in particular, a certificate of authorization from the Ministry of Sustainable Development, Environment and Parks, permits and authorizations from the concerned local municipality and RCM and, in the case of a wind farm facility located on public domain, an authorization from the Ministry of Natural Resources and Wildlife. In addition, the Commission de Protection du Territoire Agricole du Québec must render a decision to authorize the installation of wind turbines on properties located in agricultural zones.

VI. British Columbia

A. Market Structure

British Columbia's consumers have enjoyed a long history of affordable, principally hydro-based power supplied by the government-owned monopoly utility, BC Hydro. The BC Government's strategy is for 90% of this supply to be self-sustaining and based on clean or renewable resources. The strategy expressly excludes nuclear energy development.

During the last 5 – 10 years, British Columbia has been a keen observer of the electricity market changes across Canada, primarily led by the Provinces of Ontario and Alberta, as discussed above. However, despite some willingness to tinker on the edges of market design, including establishing an open access transmission tariff in 2005, the BC Government remains firmly committed to publicly-owned generation and transmission assets.

1. British Columbia Hydro and Power Authority

The British Columbia Hydro and Power Authority ("**BC Hydro**") is the dominant generator, purchaser and distributor of electricity in BC. It is a corporation owned by the Government of B.C. In February 2007, the BC Government released its current Energy Plan, titled "A Vision for Clean Energy Leadership". In it, the Government re-affirmed that BC Hydro will remain a publicly-owned corporation.

Under the *BC Hydro Act*, the Board of Directors of BC Hydro is appointed by the Cabinet of the Provincial Government. The BC Hydro Act also sets out BC Hydro's powers, which includes the authority to generate, manufacture, distribute and supply power; to develop power sites and power projects; to acquire and store water; to purchase and dispose of property; to integrate existing power plants; and to purchase power or sell power. These powers are subject to the requirements of being a regulated public utility under the *Utilities Commission Act* administered by the BC Utilities Commission (discussed further below). These powers are also subject to Cabinet direction from time to time.

As the largest electricity producer in BC, BC Hydro accounts for 80% of BC's total capacity to generate electricity, mostly from dams on the Peace and Columbia Rivers. These facilities account for 85% of BC Hydro's annual generation of between 43,500 and 54,000 gigawatt hours ("**GWL**"). The balance is produced through thermal generation, mostly fuelled by natural gas. BC Hydro has indicated that electricity demand is expected to grow by up to 45% over the next 20 years. This need will be greatest in the Lower Mainland and Vancouver Island regions, which consume about 70% of the Province's electricity demand. As discussed below, a portion of this supply is expected to be provided by clean independent power producers. In addition, BC Hydro has recently announced that it is exploring building a new dam on the Columbia River, known as Site "C", to meet this future need.

2. British Columbia Transmission Corporation

In 2003, the BC Government operationally segregated BC Hydro's transmission assets by creating another Crown corporation, the British Columbia Transmission Corporation ("**BCTC**"). BCTC's main mandate is to independently plan, manage, operate and provide non-discriminatory access to BC Hydro's transmission system. BC Hydro continues to own the transmission system assets.

Like BC Hydro, BCTC was established by legislation, the *Transmission Corporation Act* (the "**TCA**"), and like BC Hydro, BCTC is regulated by the BC Utilities Commission.

Effective March 1, 2006, BCTC's open access transmission tariff became effective. The tariff is based on the U.S. Federal Energy Regulatory Commission's ("**FERC**") Order 888 pro forma tariff. The tariff establishes a stepped rate, a time-of-use rate, and retail access.

3. Powerex

Powerex is the wholly owned power marketing subsidiary of BC Hydro. Powerex has been granted a Power Marketing Authorization from the U.S. Federal Energy Regulatory Commission and is able to buy and sell power anywhere in the United States and deliver power directly from British Columbia.

4. Independent Power Producers and the Competitive Market

Although BC Hydro is the central player in BC electricity generation and sale, the political shift in 2001 from a left wing government to the right wing Liberal party brought recognition that private sector diversification in generation should be fostered. In 2003, the BC Government directed BC Hydro to establish a competitive bidding process to acquire electricity from independent generators or power producers ("**IPPs**").

To facilitate the goal of increased private sector generation, in June 2002, the Government established an exemption for IPPs selling power to BC Hydro from being regulated as a public utility under the *Utilities Commission Act*, (the "**UCA**"). This alleviates one approval aspect of constructing and operating a power project but all other regulatory permits, such as those needed under environmental impact assessment legislation or for using water or occupying provincial land (including access rights), apply to such projects. In addition, under the UCA, all EPAs awarded to an IPP by BC Hydro must be filed with the Utilities Commission and are subject to the Commission's review.

Prior to 2003, it was the case and, indeed it remains the case, that a generator of electricity can directly negotiate a power purchase agreement with BC Hydro.

There are several examples of these negotiated agreements over the last 15 years. However, the formal competitive bid process has structurally altered BC's power market.

BC Hydro held its first "Open Call for Power" process in 2003 and 16 IPP projects were awarded long-term electricity purchase agreements ("**EPAs**") representing 1,761 gigawatt hours ("**GWh**"). Of these 16 awarded EPAs, only one project has been completed to date and this Call for Power is generally considered a significant failure. One of the contributing reasons is that a bid cap price of $55 per megawatt hour ("**MWh**") was set by BC Hydro.

In April 2006, BC Hydro held another "Open Call for Power" seeking 2,500 GWh per year of firm energy. This time, the results were a considerable success. In August 2006, 38 EPAs were awarded to IPPs totalling about 7,000 GWh of energy per year. This was based on a bid field of 53 projects representing an estimated 8,300 GWh/year. Of these 38 EPAs awarded, there are: 29 hydro electric run-of-river projects, three wind, two biomass and two waste heat and two coal/biomass projects. None of the proposals are natural-gas based, a result of the fluctuating price of that commodity and its incompatibility with BC Hydro's fixed, long-term pricing.

On September 21, 2006, the BC Utilities Commission approved these 38 EPAs as cost effective, albeit with some trepidation about BC Hydro's supporting load and risk analysis. While the individual bid prices are confidential, this BC Utilities Commission decision states that BC Hydro calculates that the nominal payment in 2012 (the first full year of purchases under the 2006 Call) will be $87.80/MWh, or $79.50/MWh deflated to 2007 dollars, while BC Hydro's average cost of bulk power (reflecting the existing heritage assets infrastructure) in 2007 dollars is $33.10/MWh.

The results of the 2006 Call for Power process and other market factors have attracted tangible investment interest in BC's IPP community with the expectation that many of this recent round of projects will be developed by 2010. For example, shortly after the EPA awards were announced, Plutonic Power Corporation, an IPP with one of the largest proposed run-of-river projects in BC at 196MW (which secured an EPA for this project), issued a press release advising that GE Energy Financial Services will invest $100 million in equity in this run-of-river project and lead a $400 million debt financing for project construction. In July 2007, Plutonic commenced construction.

Following recent consultation with the IPP community, BC Hydro is currently designing its 2007 Call for Power, named the Green Power Call, with an expectation it will proceed in the early spring of 2008. The Green Power Call will seek 5,000 GWh per year of firm energy. In addition, as directed in the 2007 Energy Plan, BC Hydro has recently announced that it is developing a standing offer program for small IPPs up to 10 megawatts. The design guidelines for this standing offer program are spelled out in the BC Government's Action Plan that accompanies the 2007 Energy Plan which includes the following general principles:

•Simplify the process, contract terms and conditions for small power projects in BC;

•Competitive pricing for these projects relative to other supply sources; and

•Ensure cost-effectiveness, transparency, and fairness of the program.

B. Regulation

1. Policy Setting

The Government of BC, primarily through the Ministry of Energy, Mines and Petroleum Resources, determines energy policy and sets the regulatory direction for BC Hydro, BCTC and sometimes the Utilities Commission (as discussed further below). The Government's current Energy Plan, The BC Energy Plan: A Vision for Clean Energy Leadership, was issued in February 2007 and is centered around the theme of ensuring a secure, reliable supply of affordable energy in an environmentally responsible way. As noted, this Energy Plan reaffirms the Government's commitment to maintain public ownership of the BC Hydro assets. It also sets a green direction for shaping the future market.

2. BC Utilities Commission

The British Columbia Utilities Commission (the "BCUC") regulates electric utilities in BC and is charged with protecting the public interest pursuant to the UCA. The BCUC has the authority to regulate all public utilities, a broad definition which covers virtually the entire electricity market in the Province. As noted above, IPPs have been primarily exempted from the BCUC's oversight.

Each of BC Hydro and BCTC are regulated by the BCUC. For example, in order for BC Hydro to set rates, it must file schedules showing its rates with the BCUC. Any changes to the schedules affecting the rates must be approved by the BCUC based on an inquiry that such rates are not unjust or unreasonable.

VII. Additional Provinces with Monopoly Utilities

A. Provinces with publicly- and privately-owned electricity monopolies

The regulation of electricity in Canada varies from province-to-province, as noted above, meaning that each provincial model displays its own idiosyncrasies. The remaining six Canadian provinces are (roughly from west to east) Saskatchewan, Manitoba, New Brunswick, Nova Scotia, Prince Edward Island, and Newfoundland and Labrador. The primary commonality between these provinces is what can loosely be termed as a traditional regulatory model, characterized by the presence of a monopoly utility (either Crown- or privately-owned). Some of these provinces have adopted certain aspects of a competitive electricity model, while others remain solid monopolies. In what follows, an overview is provided of the regulatory and market structure in each of these remaining provinces.

B. Overview of remaining provinces

1. Saskatchewan

(a) Market Structure and Regulation

SaskPower, a provincial crown corporation, is the owner of *Saskatchewan's* generation, transmission and distribution facilities. It operates pursuant to the *Power Corporation Act*, (the "**Power Corporation Act**"). SaskPower's board of directors answers to the responsible Minister of the government. Reviews of SaskPower's rates are triggered at the request of the Minister of Crown Management Board and conducted by the Saskatchewan Rate Review Panel. The Panel's decisions with respect to rates must be approved by Cabinet. Saskpower is a member of the Midwest Reliability Organization ("**MRO**"), which is a Regional Reliability Council within the North American Reliability Counsel.

(b) OATT and Power Marketing

SaskPower implemented an Open Access Transmission Tariff ("**OATT**") in 2001, which opened the Province's electricity system to wholesale access. The SaskPower OATT is consistent with the pro forma U.S. Federal Energy Regulatory Commission tariff and allows market participants to export electricity, to wheel power through the province, or to sell power to the two independent municipal utilities in Swift Current or Saskatoon. Market participants eligible to access transmission pursuant to the tariff include suppliers and traders from outside the province that wish to wheel energy through the province, the independent municipal utilities in Swift Current and Saskatoon (and any wholesalers that trade with those utilities) and the IPPs that are connected to the SaskPower grid.

In conjunction with the implementation of the OATT in 2001, NorthPoint Energy Solutions, Inc. ("**NorthPoint**"), a wholly-owned subsidiary of SaskPower, was formed to meet the OATT requirement that transmission be separated from marketing. NorthPoint provides generation and load management services, and also conducts energy trading operations with respect to the output from SaskPower's generation assets. These trading activities typically involve the marketing of surplus power in other jurisdictions and procuring power to meet domestic demands during events of production shortfall or when it is economically advantageous to do so.

(c) IPP Opportunities

SaskPower generates the vast majority of its own power, although it does procure additional supply from IPPs. SaskPower has issued a number of RFPs for generation from IPPs in recent years, and had also entered into partnerships or PPAs with cogeneration facilities. As with most other Canadian provinces, Saskatchewan's generation development policies have been influenced by environmental and climate change concerns. SaskPower's renewable energy strategy is intended to ensure that all new electricity generation in the immediate term is based on environmentally friendly technologies. SaskPower has also recently concluded its Environmentally Preferred Power ("**EPP**") RFP process. The first of two EPP RFPs resulted in SaskPower's acceptance of four projects totalling 37.85 MW, and the second RFP resulted in the acceptance of four projects totalling 32 MW. While the policy direction of SaskPower appears to be to primarily develop generation projects itself, it has stated that it will continue to work with IPPs that wish to develop viable and cost-effective projects.

2. Manitoba

(a) Market Structure and Regulation

Manitoba Hydro is a Crown corporation established pursuant to the *Manitoba Hydro Act* and is owned by the Province of Manitoba. The Manitoba Hydro Act gives Manitoba Hydro control over the province's electricity market. It is the only electricity utility in the province and it is governed by the Manitoba Hydro Electric Board. This Board, which is appointed by the provincial cabinet, reports to the Minister responsible for *Manitoba Hydro Act*. Manitoba Hydro owns and operates the Province's generation, transmission and distribution systems. The Manitoba Public Utilities Board regulates retail electricity rates pursuant to the *Manitoba Public Utilities Board Act*. The Department of Science, Technology, Energy and Mines, which was established in 2002, has a mandate to further develop Manitoba's energy sector, including through involvement in emerging energy technologies such as wind generation. Like SaskPower, Manitoba Hydro is a member of the MRO. Manitoba Hydro is also a member of the Mid-continent Area Power Pool ("**MAPP**"), which functions as a generation reserve sharing pool.

(b) OATT

Manitoba Hydro implemented its non-discriminatory OATT in 1997. Manitoba Hydro's tariff is in keeping with the pro-forma FERC tariff, allows for third party use of its transmission system provided capacity is available, and thus facilitates reciprocity for those third party users. The key benefit to Manitoba Hydro is that this enables it to maximize its opportunities for electricity export into U.S. markets which require reciprocal access. Manitoba's electricity prices have consistently been the lowest in Canada, which enhances its position as an exporter. Manitoba's OATT also provides the ability to wheel power through the province. Manitoba does not have a developed wholesale market for electricity at present.

(c) IPP Opportunities

Generation development by IPPs has only recently occurred in Manitoba. Manitoba Hydro is actively involved in developing its own new generation, although there are presently some opportunities for IPPs to develop projects independently of the utility. The greatest opportunities for IPP developers in Manitoba appear to be with respect to wind generation. An RFP for wind power in 2003 resulted in 36 proposals; the successful proponent was the 99 MW St. Leon project. In 2006, the Manitoba government announced a target of developing 1000 MW of wind generation over the following decade. An initial RFP for the first 300 MW of this target closed in July, 2007. Three further allocations of 200 MW each are expected in 2013-14, 2015-16 and 2017-18. Manitoba Hydro has given notice that it will not bid on these RFPs, presumably in order incent IPPs to participate.

3. New Brunswick

(a) Market Structure and Regulation

In 2004, New Brunswick implemented the *Electricity Act*. Pursuant to this legislation, the provincially-owned utility, NB Power, and the province's electricity market, underwent a substantial change. NB Power was reorganized from a unitary structure into a holding company with subsidiary operating companies. The market was changed by the creation of a competitive environment for eligible wholesale, industrial, and municipal utility customers. Distribution-connected customers continue to purchase power on a regulated basis from NB Power as they had previously done. As discussed below, the new legislation also expanded opportunities for IPPs to participate in the development of new generation.

The *Electricity Act* also provided for the creation of the New Brunswick System Operator ("**NBSO**"). The NBSO is a not-for-profit, Crown corporation with an independent board of directors. Its primary responsibility is to ensure the security and reliability of the electricity system and to oversee access to the transmission grid. The NBSO also administers New Brunswick's OATT and the market rules. The NBSO has established a market advisory committee that includes representatives from a wide range of interested parties. Any changes to the market rules must first be approved by the market advisory committee.

The *Electricity Act* has also expanded the role and responsibilities of the New Brunswick Energy and Utilities Board. Any rate increases over three per cent annually for any given rate class continues to require approval by the Energy and Utilities Board, however its mandate now also includes that of monitoring the electricity market, including with respect to its efficiency, fairness, transparency and competitiveness of the market; reporting on the conduct of the system operator and market participants; providing advice on the abuse or potential abuse of market power; and issuing licenses to market participants.

New Brunswick is the only Atlantic Canadian province that operates nuclear generating assets; NB Power's Point Lepreau generating station has a net capacity of 635 MW and supplies approximately 25% of all the electricity consumed in New Brunswick.

(b) OATT

In conjunction with the limited wholesale market described above, New Brunswick implemented an Open Access Transmission Tariff on September 30, 2003. The OATT is founded upon a FERC Order 888-type open access tariff. The New Brunswick market is a physical bilateral market, and as such is premised upon the ability to inject and withdraw power through the New Brunswick transmission system. The New Brunswick OATT also accommodates the transfer of power to neighbouring provinces as well as its export to the United States. In addition, the OATT allows for power to be wheeled through New Brunswick: Nova Scotia, for example, has utilized this opportunity to undertake limited exports to the state of Maine.

(c) IPP Opportunities

The *Electricity Act* provides that as generating assets are retired or as additional supply is required, standard service suppliers (i.e. the distribution companies) will procure new supply through the competitive market. This means that any new resources required by the NB Power Distribution Corporation will be acquired through procurement processes open to both IPPs as well as NB Power Generation Corporation.

The *Electricity Act* has also led to other opportunities for IPPs. For example, the Electricity from Renewable Resources Regulation, issued under that Act, requires NB Power to acquire 10% of its electricity supply from renewable sources by the year 2016. As a result, NB Power has stated that it will acquire 400 MW of wind power in order to meet that requirement, and in May 2007, it initiated a 300 MW wind power RFP.

4. Nova Scotia

(a) Market Structure and Regulation

Nova Scotia Power Incorporated ("**NSPI**") is a monopoly utility that provides 97% of the generation, 99% of the transmission, and 95% of the distribution in the province of Nova Scotia. The remaining distribution is owned and operated by Nova Scotia's six municipal utilities. NSPI was privatized in 1992, and is now owned by Emera Inc., a publicly-traded company. NSPI is regulated on a cost-of-service basis by the Nova Scotia Utility and Review Board, pursuant to *Nova Scotia's Public Utilities Act*.

The introduction of *Nova Scotia's Electricity Act* in 2004 has set in motion a number of structural changes to the province's electricity market. A limited wholesale market has been created for eligible market participants (i.e. the province's six municipal utilities), which allows these customers to purchase electricity from any competitive supplier. In order to facilitate the operation of this market, the *Electricity Act* also required NSPI to file with and seek approval from the Utility and Review Board for an OATT. The filing of the OATT in 2005 also allowed NSPI to meet another requirement of the Electricity Act, which was that it develop and maintain a system to facilitate the import and export of electricity into and out of the province.

(b) OATT

The *Nova Scotia Electricity Act* required NSPI to file an Open Access Transmission Tariff in order to provide non-discriminatory access to its transmission system; the OATT was approved by the Nova Scotia Utilities and Review Board on May 31, 2005. The OATT is modelled after the pro-forma U.S. FERC Order 888 tariff, and according to NSPI, meets the reciprocity requirements of other jurisdictions that have implemented FERC-type OATTs. The Nova Scotia OATT allows IPPs and marketers to import and export power, allows Nova Scotia's limited number of wholesale customers to seek supply from outside the province.

(c) IPP Opportunities

As noted above, almost all (97%) of the electricity produced in Nova Scotia is generated by the monopoly utility. NSPI does, however, occasionally engage in regulated RFPs to procure power from IPPs. Recently, the province's desire to increase its supply of renewable energy has created some new opportunities for IPPs in the area of renewable generation. Nova Scotia's Renewable Energy Standard Regulations, which became effective on February 1, 2007, requires that by 2013, a minimum of 10% of the electricity supplied in the province must be from renewable sources. In fact, the government has stated that by 2013, 20% of the province's power will come from renewables.

There is currently approximately 60 MW of IPP-produced power on the Nova Scotia system. In 2004, NSPI released a Renewable Energy Solicitation for 100 GWh of power per year for twenty years. As a result of this solicitation, two wind power projects were signed, with respective capacities of 14 and 31 MW. In March 2007, NSPI commenced a subsequent RFP for a further 130 MW of renewable electricity, of which 30 MW will be reserved for small, distribution-connected projects.

5. Prince Edward Island

(a) Market Structure and Regulation

Prince Edward Island ("**PEI**"), Canada's smallest province, is served by Maritime Electric Company Limited ("**Maritime Electric**"). Maritime Electric is a wholly-owned subsidiary of Fortis Inc. With the exception of the municipal distribution utility operated by the City of Summerside, it is the province's only utility. Maritime Electric is regulated by the Island Regulatory and Appeals Commission pursuant to PEI's Electric Power Act. This legislation was proclaimed on December 20, 2005, and returned Maritime Electric to a traditional cost-of-service regulatory model. Prior to this, Maritime Electric's rates has been linked directly to NB Power rates. The link to the NB Power rates was due to the fact that most of the electricity supplied by Maritime Electric is purchased from NB Power, and comes to PEI via two submarine transmission cable that cross the Northumberland Strait. Maritime Electric also owns and operates two generating stations on PEI, which are kept in standby mode in order to accommodate interruptions of the off-Island supply.

(b) IPP Opportunities

Prince Edward Island's policy direction with respect to electricity generation development has turned toward renewables, and particularly wind generation. Public statements by the provincial government have clearly expressed an intention to aggressively pursue the development of the Island's wind resource. In 2004, PEI passed the Renewable Energy Act, which requires the province's utilities to acquire 15% of electricity supply from renewable sources by 2015. In order to stimulate the development of renewable generation on the Island, the government passed the Minimum Purchase Price Regulation. The rate set by the Regulation is 7.75 cents per kilowatt hour, with 5.75 cents of that a fixed rate and 2.0 cents a variable rate that may be adjusted annually to reflect changes in operating costs.

The province has developed the North Cape wind farm through the Prince Edward Island Energy Corporation ("**PEI Energy Corporation**"), a Crown-owned entity. A private entity has also signed a PPA with the Prince Edward Island Energy Corporation in connection with a second wind farm. To date, no RFPs have been commenced, and there is no indication that the province's pursuit of wind generation will proceed by public procurement. In fact, it appears that the PEI Energy Corporation may be the primary vehicle through which this development occurs. In the provincial government's 2004 document, titled "Energy Framework and Renewable Energy Strategy", it stated that, "[t]he PEI Energy Corporation will remain actively involved in advancing and developing wind projects in Prince Edward Island". As such, the extent of the opportunities for IPPs in PEI to participate in the development of wind generation remain to be seen.

6. Newfoundland and Labrador

(a) Market Structure and Regulation

Newfoundland and Labrador Hydro (“**NL Hydro**”), a Crown corporation, owns and operates most of the generation and transmission facilities in this province. NL Hydro is also the distribution company for mainland Labrador, the Great Northern Peninsula on the island portion of the province, and many rural communities along the island’s coastline. NL Hydro’s installed capacity of 7289 MW includes 1552 MW on the island and 5428 MW in Labrador – most of the latter being exported to Hydro Quebec under a long term contract that is very controversial within the province. Newfoundland Power, which is owned and operated by the publicly-traded Fortis Inc., is the main distribution company. It serves approximately 90% of the island’s retail customers, which represents 80% of the province’s population. Newfoundland Power sources 90% of its electricity from NL Hydro, with the remainder being supplied by small IPPs.

The provincial Department of Natural Resources is charged with the duty of facilitating the efficient and effective management of the province’s electricity resources. Both NL Hydro and Newfoundland Power are regulated by the Newfoundland and Labrador Board of Commission of Public Utilities, pursuant to the province’s Public Utilities Act and the Electric Power Control Act. The Public Utilities Board is an independent, quasi-judicial regulatory agency. Its criteria in regulating the utilities are to ensure that the rates charged are just and reasonable, and that the service provided is safe and reliable. One exception to the regulatory overview of the Public Utilities Board is with respect to rates for major industrial consumers in Labrador; contracts with these large consumers have historically been set through direct contractual arrangements, a situation that the present government has stated will continue for the foreseeable future. Newfoundland and Labrador does not have an OATT in place.

In 2007, the province released its Energy Plan, which establishes a framework for the government’s long-term policies for developing its energy resources. Among the initiatives established in the Energy Plan is the creation of a wholly-owned Energy Corporation. In June 2007, the Energy Corporation Act was passed (although it is not in force at the time of writing) which provides for the creation of this new entity. The Energy Corporation will become the parent corporation for NL Hydro, Churchill Falls Labrador Corporation (which owns the Churchill Falls hydroelectric station), other NL Hydro subsidiaries, as well as other new entities that will be created to manage provincial investment in the energy sector.

(b) IPP Opportunities

NL Hydro has been purchasing power from IPPs since 1998. It currently has contracts in place with four NUGs for a total of approximately 66 MW of supply. As noted above, Newfoundland Power also procures a small portion of its requirement from IPPs. NL Hydro has also recently concluded two RFPs, each for 25 MW of wind power. Although the utility and the provincial government have both expressed a desire to further develop the province's wind resources, it is unclear what opportunities will be available to IPPs in the future. The province's recent Energy Plan indicates that forthcoming policies may focus on utilizing the new Energy Corporation as the primary vehicle for future development. The Energy Plan indicates that IPPs may, at the very least, be required to partner with the Energy Corporation in future generation projects, and that the Energy Corporation will control such developments. The Energy Plan makes this clear, stating that the government will "enable this by adopting a policy that no new leases for wind development on crown land will be issued except to the Energy Corporation or another company acting in partnership with the Energy Corporation".

VIII. Imports and Exports of Electricity

Regulatory jurisdiction over the operation and the construction of international power lines is vested in the National Energy Board ("**NEB**"), a federal agency established under the *National Energy Board Act* (the "**NEB Act**"). The NEB Act defines an "international power line" as facilities constructed or operated for the purpose of transmitting electricity from or to a place in Canada from or to a place outside of Canada. The NEB has interpreted the term as including any section of an international power line located within a province and serving both a domestic and an international load. A person may construct or operate an international power line, but only in accordance with a permit or a certificate issued by the NEB. A person who wishes to export energy produced in Canada must obtain either a permit or licence from the NEB. That person must also register with the IESO a boundary entity to which the export transmission will relate.

The NEB also has jurisdiction over an inter-provincial power line, where the federal Cabinet designates such line as an international power line. To date, no inter-provincial power line has been so designated. Accordingly, provincial regulators retain jurisdiction over existing inter-provincial power lines.

A. Alberta

All electricity transactions in Alberta, including inter-provincial transfers and international exports and imports, must occur through the Power Pool. The NEB reports that in 2004 Alberta sent 1400 GWh of electricity to British Columbia and that it exported over 100 GWh to the U.S. At present, Alberta's primary access to the U.S. markets is through the interties to British Columbia, as there is no direct transmission line between Alberta and the U.S. Albertan electricity can also access the U.S. markets indirectly through Saskatchewan. The Montana Alberta Tie Ltd. is proposing to build a 300 KM transmission line from Alberta to Montana. To date, MATL has received a number of the required approvals from regulators on both sides of the border, and appears to be close to final AEUS approval before the commencement of construction.

B. Ontario

Ontario currently has approximately 4,000 MW of interconnected transmission capacity with adjacent provinces and states. Ontario is pursuing further interties of approximately 2,000MW with Manitoba and with Québec. Export transmission service is available from the IESO to any Market Participant seeking to deliver electricity over the IESO-administered grid to loads or transmission systems located outside Ontario. The IESO collects the charges for export transmission service from each transmission customer that exports energy out of the IESO grid. The Market Participant is responsible for any arrangements with entities outside Ontario necessary to deliver electricity from the IESO-administered grid to the relevant adjacent market. In 2004, transfers to other Canadian provinces amounted to approximately 9,000 GWh, while 8,000 GWh were exported to the U.S.

C. Quebec

Quebec has significant inter-provincial transmission links with Ontario, New Brunswick and Labrador. Through its contract with NL Hydro, Hydro Quebec receives approximately 30,000 GWh from Churchill Falls annually. In recent years, inter-provincial transfers into Quebec have increased as the supply situation in that province has tightened. The growth in domestic demand has also caused exports to decline as a result of lower surpluses being available for export. Most exports are for short-term spot transactions. Hydro Quebec has announced that it is pursuing technical solutions that would allow it to increase its wheeling capacity. It is examining increasing its wheeling capacity with New York state from 1,500 to 1,800 MW, and with the New England states from 1,500 to 2,000 MW.

D. British Columbia

On an inter-provincial level, British Columbia regularly conducts power transfers with Alberta. Because Alberta's system is predominantly baseload and thermal facilities, and British Columbia's is primarily based on hydro, there is a flow of power out of British Columbia during peak hours, and into British Columbia during off-peak hours. In 2004, transfers from British Columbia into Alberta totalled approximately 1,200 GWh. British Columbia also has 500 kV lines and two 230 kV lines connecting it to the U.S. These interties provide access to the neighbouring states and also indirect access to California. Traditionally, the interties provided an access to export markets for BC; however, as a result of market factors in the U.S., export margins and opportunities have decreased somewhat in recent years. Additionally, British Columbia recently increased its importation of electricity as a result of lower than average hydroelectric conditions, increased demand, and restrictions on transmission into California. In 2004, transfers to the United States totalled approximately 6000 GWh.

E. Manitoba

Manitoba is a net exporter of electricity. Transmission lines connect the province to Saskatchewan, Ontario, North Dakota and Minnesota. On average, approximately 30% of the electricity generated in Manitoba is sold to other Canadian provinces or to the U.S. markets. The intertie connections to Saskatchewan and Ontario are of low capacity. The Saskatchewan intertie has a typical capacity of approximately 375 MW. The intertie with Ontario is currently limited to approximately 200 MW, although the two provinces have been exploring the possibilities for the expansion of the transmission links between them. The interconnection through Saskatchewan to Alberta is also constrained, limiting transfers from Manitoba to Alberta. However, export capacity to the U.S. markets is much greater, at approximately 1,850 MW in total. A significant portion of Manitoba's output each year is exported into Minnesota, as the large interconnections provide access to Minneapolis, the closest major population (and thus load) to Manitoba.

F. Atlantic Canada

New Brunswick is the one Atlantic Canadian province (the others being Nova Scotia, PEI and Newfoundland and Labrador) that has a physical border with the U.S. In 2004, its transfers to other provinces totalled approximately 2500 GWh, while its exports to the U.S. amounted to approximately 2000 GWh. As a result of New Brunswick's implementation of its OATT, Nova Scotia and PEI have access to the U.S. markets due to the possibility of wheeling power through New Brunswick. While both PEI and Nova Scotia hold export permits from the NEB, neither province has a significant cross border trade at this point, although Nova Scotia has been involved in some limited power exports to the state of Maine.

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