TAB 6

Case Name:

Hydro One Networks Inc. (Re)

**IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c. 15 (Sched. B);
AND IN THE MATTER OF a proceeding pursuant to subsection 19(4), and 74 of the Ontario Energy Board Act, 1998 to review the Transmission System Code and Related Matters.**

2004 LNONOEB 3

No. RP-2002-0120

Ontario Energy Board

Panel: Paul Sommerville, Presiding Member; Art Birchenough, Member; Fred Peters, Member

Decision: June 8, 2004.

(364 paras.)

PHASE I POLICY DECISION WITH REASONS

TABLE OF CONTENTS

VOLUME I

1. THE PROCEEDING

1.1 HYDRO ONE APPLICATION FOR AMENDMENTS TO THE TRANSMISSION SYSTEM CODE

1 On September 27, 2001 and October 17, 2001 Hydro One Networks Inc.("Hydro One") submitted proposed amendments to the Transmission System Code (the "Code"). This submission was given file number RP-1999-0057, which is the general file number for this Code.

1.2 HYDRO ONE REQUEST FOR APPROVAL OF ITS CONNECTION PROCESS

2 On January 30, 2002, Hydro One submitted, in accordance with section 4.1.5 of the Code, its proposed Customer Connections Process. This filing was given file number RP-2002-0101 / EB-2002-0242.

1.3 ONTARIO POWER GENERATION APPLICATION FOR AMENDMENT OF HYDRO ONE LICENCE

3 On March 4, 2002, Ontario Power Generation Inc. ("OPG") applied for an order of the Board to amend Hydro One's Transitional Transmission Licence number ET-1999-0332. This filing was given number RP-2002-0110. On December 3, 2003, Hydro One's Transitional Transmission Licence was subsequently renewed and replaced with an end-state Transmission Licence number ET-2003-0035.

1.4 THE BOARD, ON ITS OWN MOTION

4 In addition to these applications, the Board had also received expressions of concern from various stakeholders, regarding the interpretation and application of the Code. As a result, the Board was of the view that it would be appropriate to review the entire Code, and as part of that process, deal with the applications that had been filed.

1.5 NOTICE OF PROCEEDING

5 On June 14, 2002, the Board published its Notice of Proceeding, indicating its intent to review the Code, and to consolidate that review with the applications that had been received. The Notice was mailed directly to potential participants and it was posted on the Board's website. The Board assigned the consolidated Proceeding file no. RP-2002-0120.

6 The Notice of Proceeding invited interested persons to write to the Board, requesting intervenor status and providing a description of issues, comments or proposed amendments they intended to address in the Proceeding. Throughout this Proceeding, the Board received in excess of 130 submissions. A list of the parties and their associated acronyms, is set out in Appendix A to this Decision.

7 The Board reviewed the submissions and determined that it would be best to divide the Proceeding into two phases: Phase 1, which would address policy issues, and provide the principled framework for detailed Code revisions, and Phase 2, which would present specific Code amendments based on the principles developed in Phase 1 and deal with the implementation issues as well as issues arising out of the applications filed by Hydro One and OPG.

8 This Decision is the culminating element in Phase 1. Attached, as Appendix C, is a brief synopsis summarizing the more significant aspects of the Decision and the Board's associated rationale.

9 In Phase 2, which will follow this Decision forthwith, the Board will produce a revised Code incorporating the policy decisions reflected in this Decision. In accordance with the statutory provisions governing this process, Parties will have an opportunity to make submissions on the draft Code before it is adopted by the Board.

10 In a separate joint application filed by OPG, Bruce Power, and Hydro One (Board File No. EB-2002-0501), the Board is considering proposed amendments to the form of the connection agreement which is Appendix 1 of the Code. These amendments include proposals to address specific operational requirements for the safety of nuclear generating sites, and certain legacy issues related to generating site requirements for both conventional and nuclear sites. Parties will have an opportunity to make submissions regarding the proposed changes contained in the joint application.

Board findings related to this Proceeding will be incorporated into the revised Code, and will be circulated to all parties for further comments before issuing the revised Code.

1.6 PROCEDURAL ORDERS

11 On August 30, 2002, the Board issued Procedural Order No. 1, requesting submissions on Phase 1 issues by September 30, 2002 and reply submissions by October 21, 2002.

12 On September 20, 2002, the Board issued Procedural Order No. 2, extending the filing dates for submissions to October 31, 2002 and reply submissions to November 22, 2002, at the request of parties.

13 On April 14, 2003, the Board issued Procedural Order No. 3. The Board provided a set of Principles and a list of preliminary propositions for Phase 1 issues and requested submissions and reply submissions on these propositions. This was done to achieve a more focused discussion of the issues.

14 On July 30, 2003, the Board issued Procedural Order No. 4 establishing a Settlement Conference to be held beginning September 9, 2003.

1.7 SETTLEMENT CONFERENCE

15 A Settlement Conference was held on September 9 - 16, 2003 to review issues, seek consensus where possible, and develop workable alternatives for the Board's consideration on the following issues:

- Determination of the remaining value of an asset
- What constitutes "fully allocated costs"
- Determination of and allocation of O&M costs
    - Definition of Capacity Allocated to a Customer (CATC)
- Definition of Line Connection and Network assets
- Definition of Embedded Generation
- Proposals for true-up requirements

16 A copy of the facilitator's report from this Settlement Conference is found in Appendix B to this Decision.

17 The results of the Settlement Conference were of assistance to the Board in deciding on a number of specific issues. How the results of the Settlement Conference were incorporated with respect to specific issues is discussed in appropriate sections of the Decision.

2. PRINCIPLES

18 It is the Board's intention that the revised Code and the documents and procedures associated with it, including Hydro One's Customer Connection Process (CCP) and Connection and Cost Recovery Agreement (CCRA), should create an environment where conditions governing the relationship between transmitters and transmission customers, including generators, would be characterized by enhanced fairness, transparency and effectiveness. In order to achieve this goal and to elicit useful and focused input from the parties, the Board developed a series of Principles, which are detailed below. It was expected that some Parties would express points of view contrary to the Principle enunciated. In this way, the Board expected to receive a full spectrum of thought on the important issues raised in the proceeding.

19 The Principles were initially issued in Procedural Order No. 3. Some Principles were modified during the course of the Proceeding as indicated below.

1. *There is clear understanding of the Code and related documents and procedures with respect to the intent and objectives of the Ontario Energy Board Act, 1998 (the "Act").*

2. *The monopoly position of the transmitter does not unduly restrain competition in areas where competition can occur.*

This principle guided the Board primarily in a number of findings under Contestability.

3. *Parties are able to effect efficiencies in their use of electricity without facing punitive measures or disincentives where a transmitter may impose a minimum payment obligation to cover present loads or Available Capacity on existing Connection facilities.*

This principle guided the Board in findings 5.1.1, 5.2.1, 5.4.1, 5.6.1 and 8.9.1.

4. *New generation is not discouraged.*

This principle guided the Board in findings 5.1.1 and 5.4.1.

5. *Unnecessary transmission asset duplication is avoided.*

The Board approach recognized that "Transformation Connection" is currently a contestable area in Ontario, and thus should be managed in a different way than is the case for the Line Connection and Network pools. Transformation Connection assets can be duplicated, subject to the Board-approved approach to compensate for bypass. This issue was canvassed in Board Proceeding RP-1999-0044. Duplication, reinforcement or reconfiguration of Transmission Network assets and Line Connection assets are subject to much more stringent control, and is permitted only in certain circumstances. This principle guided the Board in findings 4.8.1 and 5.3.1.

6. *Transmission assets are considered to be stranded assets only to the extent that their value has not been captured in the revenue requirement established for the purpose of rate setting. Assets which have been fully depreciated are not considered to be stranded by bypass, and assets which have*

been partially depreciated shall be considered to be stranded only to the extent that their value has not been fully depreciated.

This principle guided the Board in finding 4.8.1.

7. *Economic evaluations should include appropriate costs and revenues that are associated with transmission connection to the extent that these accommodate new load. Economic evaluations should exclude sunk costs and historic revenues.*

The scope of this principle was expanded from its initial version to include the concept that the evaluation should be limited only to costs associated with new load. This principle guided the Board in findings 8.1.1 and 8.8.1.

8. *Load customers are held responsible for their load forecasts subject to a true-up mechanism. There are two proposed exceptions to this principle:*

   * *embedded generation units of 1MW or less; and*

   * *measures for energy conservation, energy efficiency, load management and the use of renewable energy resources.*

In these cases load customers experiencing shortfalls in projected load should receive relief through periodic true-ups and load forecast adjustment.

The scope of this principle was narrowed somewhat from the initial version by replacing "cleaner energy sources" with "renewable energy resources". This principle guided the Board in finding 8.9.1.

9. *A balance between maintaining the integrity of the transmission system and providing transmission customers with opportunities for achieving conservation, energy efficiency, load management and the use of renewable energy resources should be maintained.*

This principle originally referred to "cleaner" energy sources. However, "cleaner" can be ambiguous and remains undefined. As a result, the Board has decided to replace "cleaner" with "renewable" in this principle as well as in all other pertinent sections of this decision. A full discussion of this change can be found in section 5.2.1 which includes a definition of "renewable energy sources".

10. *Economic evaluations associated with customer connections should be done for each of the Transformation and Line Connection pools, but the two evaluations should be netted against each other for the purpose of calculating any capital contribution.*

The Board has concluded that this is a complex matter that requires further examination from a contestability, accounting and rate perspective and, therefore, will defer its decision in this regard. A full discussion can be found in section 8.4.1.

11. *Transmission Connection assets are defined as stated in Hydro One's evidence in Proceeding RP-1999-0044. The Transformation Connection pool refers to high voltage transformation facilities that step down voltages from transmission levels to distribution levels to supply customers. The Line Connection pool refers to radial transmission lines that are specifically dedicated to serving a single customer or group of customers.*

The Board accepts the prevailing view of the participants that this classification issue, as well as the issues outlined in Hydro One's Appendix B of the Settlement Agreement should be addressed prior to or at the next cost allocation and rate design proceeding. In the interim, the Board finding in this matter can be found at section 6.12.1.

12. *Transmitters may charge customers as well as the IMO for customer connection studies in one of the following ways: (1) on a time and material basis; (2) on a fixed charge basis; or (3) on a pass through basis (Note this is only for third party costs which the transmitter would be allowed to pass through to the customer without any mark up to the cost). For options (1) and (2), the charges should be based on the incremental revenue requirement beyond what is presently included in the transmitter's approved revenue requirement and associated rates. Specific fees for customer connection studies are, as a matter of law, rates, pursuant to section 78 of the Act and may not be charged to anyone without approval of the Board. Upon approval by the Board, the transmitter should publish information relating to its charges for customer connection studies along with a description of the scope of work covered by the studies.*

The changes included in this revised principle, reflect comments received from various parties. This principle guided the Board in finding 6.10.1.

13. *The Board should develop a procedure for the creation of interpretive bulletins respecting the Code which may serve to assist parties in resolving disputes.*

This principle guided the Board's finding in section 9.3.1.

14. *The Board will not examine implications of locational marginal pricing ("LMP") in this proceeding.*

3. <u>THE ISSUES</u>

3.1 ORGANIZATION OF THE DECISION

20 The Board has organized the issues raised in this Proceeding under the following headings:

* Available Capacity
* Transmission System Bypass
* Cost Responsibility
* Contestability
* Economic Evaluation
* Contractual Issues

21 For each issue, the Board has set out the preliminary propositions that were provided to the parties. This is followed by the Board's analysis and findings on each proposition.

4. AVAILABLE CAPACITY

4.1 AVAILABLE CAPACITY - BOARD PROPOSITION NO. 4.1

22 *The Code should define Available Capacity to be the unutilized supply capability on each system element (i.e., transformer station or line section) comprising a transmitter's Connection facilities.*

4.1.1 Analysis and Findings

23 Generally, there was no opposition amongst parties to this preliminary proposition, subject to some reservations. APPrO (previously known as "IPPSO"), an organization representing the interests of generators in Ontario, wanted confirmation that findings relating to Available Capacity would be confined to Connection facilities. The Board confirms that all of the propositions and findings contained in this Chapter on Available Capacity are confined to Connection facilities.

24 Hydro One was concerned that "system element" was defined at a level that would create complexities which would result in implementation difficulties or ambiguities. The Board accepts Hydro One's view that "system element" should be defined at the transformer station and circuit level rather than at the line section level.

25 Therefore, for the purposes of the revised Code, the Board finds that Available Capacity shall be defined to mean the unutilized supply capability on each system element (i.e., transformer station or transmission line) comprising a transmitter's Connection facilities.

26 APPrO asked the Board to consider the appropriate approach respecting the allocation of Available Capacity on Connection assets that had been funded, completely or in part, by a customer. APPrO proposed that the Code should allow such a customer to: (a) recover part of its contribution when Available Capacity on those Connection assets is allocated to a new customer; and, (b) have a right of first refusal over Available Capacity before it is allocated to another transmission customer.

27 As a matter of fairness, the Board is of the view that where an existing load customer has provided a capital contribution to a transmitter for a Connection asset, and the transmitter subsequently allocates Available Capacity on that asset to a new load customer, the initial customer should be compensated by the transmitter. The compensation should take into account the size of the new load, the additional incremental revenue received from the new load customer, and the proportion of

the total cost of the Connection assets that the original and new capital contributions represent. This is also addressed in section 6.3.1.

28 GLPL wanted assurance that the proposition would not prevent a transmitter from recovering its capital costs and O&M costs for existing Connection facilities. ECMI, a consultant retained by a group of distributors, submitted that the propositions do not recognize that revenue from Available Capacity, as it is taken up by new load, constitutes windfall revenue for the transmitter. In the Board's view, both of these issues relate to the revenue requirement of the transmitter and are issues that are properly addressed in a rates Proceeding. There are situations arising in the relationship between a transmitter and its customers that may lead to apparent windfall revenues for transmitters. This occurs where costs have been incorporated in the revenue requirement and then are also recovered in whole or in part from a specific customer or customers. It is expected that the transmitter, whether in connection with future rate Proceedings or otherwise would develop an approach to such circumstances which is fair and transparent.

29 CAC and VECC submitted that the identification of further technical issues and their resolution is the type of matter that could be effectively dealt with on an ongoing basis by a consultation team.

30 The Board is of the view that the opportunity afforded to parties in this Proceeding, through the filing of submissions and the Settlement Conference, provided an adequate forum for the identification and resolution of technical issues, and that a consultation team is not necessary. Available Capacity is defined in section 4.3.1.

4.2 AVAILABLE CAPACITY - BOARD PROPOSITION NO. 4.2

31 *The Code should contain provisions to prevent a transmitter's assignment of Available Capacity to a transmission load customer which intends to build and own a new connection facility for supply of new load. The customer should not be inhibited and the transmitter should not be allowed to charge new load for the sunk costs of existing Connection facilities.*

4.2.1 Analysis and Findings

32 Hydro One was opposed to this proposition on the basis that it would permit customers with new load to build parallel connection facilities when there was adequate Available Capacity on the transmitter's Connection facilities to serve that new load. Hydro One asserted that existing Connection facilities were built based on the load forecast for existing customers. To the extent that new load was part of the original forecast, allowing a customer to build its own connection facility to serve new load before the existing Connection facilities are fully loaded would, in Hydro One's view, constitute bypass and the inefficient duplication of existing assets. CAC and VECC share Hydro One's concern that existing system capacity reflects forecasts, as well as existing requirements, and that customers should not be allowed to build parallel connection facilities when Available Capacity already exists on the transmitter's Connection facilities. CAC and VECC take the position that customers should be held to their load forecasts.

33 GLPL is of the view that a transmitter should not be able to charge new load for the sunk costs of existing Connection facilities, provided that the transmitter can recover the full cost of existing Connection facilities from its customers.

34 Toronto Hydro disagrees with Hydro One that existing rates were approved on the basis of entitling a transmitter to serve future load growth from existing Connection facilities. Toronto Hydro submits that, while existing pool customers would benefit through lower rates, if rates were re-set to reflect load growth, it does not follow that existing costs would be 'shifted' to existing customers if new load were served from new customer owned connection facilities. The potential benefit to existing customers is an 'opportunity benefit', that is, their position is not prejudiced if new load is served from new customer-owned connection facilities. A negative rate impact alone does not establish that the pool has been unduly harmed.

35 The Board is of the view that a customer opting to build its own transformation connection facilities to meet new load, where that new load has not been specifically accounted for in a contract that included a load forecast underpinning a particular transmitter-owned Transformation Connection asset, does not amount to duplication or bypass. The transmitter should not have an automatic right to assign Available Capacity to service new load. Allowing a role for competition in the transformation connection market will lead to more economic efficiency on the part of the transmitter. In other parts of this Decision, the Board will establish the basis on which existing load is to be distinguished from new load (section 4.3.1), as well as rules relating to contestability (Chapter 7).

36 The Board therefore finds that, for the purposes of the revised Code, transmitters will not automatically be entitled to serve new load growth, where that new load has not been specifically part of a forecast underpinning existing Transformation Connection facilities and included in a contract freely entered into by the parties. As such, the revised Code shall contain provisions to prevent a transmitter's assignment of Available Capacity to a transmission load customer intending to build and own a new transformation connection facility for the supply of new load. Where a customer opts to service such load through its own transformation connection facilities, this will not constitute bypass.

37 In section 4.8.1, the Board further prescribes the criteria for allowing bypass of Connection facilities serving existing load and, where allowable, the basis for compensation.

4.3 AVAILABLE CAPACITY - BOARD PROPOSITION NO. 4.3

38 *Each connection agreement with any new customer should specify the amount of capacity that has been allocated to each delivery point for that customer. This will be referred to as the "Capacity Assigned to Customer (CATC)" approach.*

39 *For existing customers, the amount of CATC per delivery point should be deemed to be the <u>greater</u> of either:*

> *1. the highest monthly peak load over the past 5 years for the relevant delivery points; or*
>
> *2. the Available Capacity of the existing dedicated feeder positions associated with the relevant delivery point.*

40 *Available Capacity is then determined by subtracting the total CATC for all customers from the total capacity of Line and Transformation Connection facilities.*

4.3.1 Analysis and Findings

41 Hydro One agreed that a transmitter should be required to calculate and make information available to customers respecting Available Capacity at Connection facilities. However, Hydro One did not agree that Available Capacity should be assigned to specific customers using a CATC approach. Hydro One submitted that this would allow customers to reserve Available Capacity and this may be contrary to the *Electricity Act, 1998* and Market Rules. The use of existing Connection facilities should be maximized and the construction of redundant connection facilities avoided. Hydro One was also concerned that this approach could lead to a customer being entitled to Available Capacity that they are not currently using. This could result from gaming, such as in circumstances where a customer has created an artificially inflated peak load to secure Available Capacity for an unspecified and uncertain future load growth contingency.

42 OPG and Brighton were concerned that there is potential for confusion as to whether the CATC approach relates only to Connection assets or to Network assets as well. In their view, allocation of Network capability is plagued by complexities and unintended consequences, and runs counter to other propositions proposed by the Board. They strongly recommended that the CATC approach should unequivocally apply to Connection assets exclusively.

43 Imperial submitted that the CATC approach for existing customers should allow a customer the opportunity to demonstrate that a different approach for allocating capacity may be fairer, more accurate, or otherwise more appropriate. An example of when this might be appropriate is where a customer has carried out structural changes to its consumption patterns that make the use of the highest monthly peak over the past 5 years a misleading and inappropriate determinant.

44 The EDA suggested that for temporary load transfers, instead of using the highest monthly peak load, the average of 3 consecutive month's peak load (a rolling average demand), established within 5 years prior to a new connection, should be used. In the EDA's view, the Code should define and prohibit gaming in artificial peaks. Toronto Hydro supported the EDA's position. It also agreed with Hydro One's view that Available Capacity is dynamic in nature, particularly for Connection facilities serving large end-use customers. Nevertheless, Toronto Hydro submitted that it would be appropriate and beneficial for the Code to contain explicit rules governing the allocation of capacity on a customer-specific basis.

45 ECMI submitted that the Code should take into account the ability of distributors, primarily Hydro One Distribution, to move load between Connection facilities and claim capacity at multiple Connection facilities with the same load, thereby reducing Available Capacity for others on a given Connection facility. CATC allocation should be made on the basis of normal supply, recognizing that load movement can be a response to a genuine emergency situation. Use of the highest monthly peak load over the last 5 years may represent an emergency situation rather than a normal supply situation. The Code should contain provisions allowing the OEB to review initial and subsequent assignments of Available Capacity and make any necessary adjustments. In its view, the same load should not be used to establish CATC for more than one Connection facility. If backup supply capacity is to be earmarked as CATC, it should be designated as backup CATC, with different attributes and financial considerations.

46 CAC and VECC asked the Board to clarify whether CATC would be a one-time calculation or an annual calculation given that total loads for many transmission customers, for example, distributors, are growing annually.

47 The CATC preliminary proposition was addressed at the Settlement Conference (See Issue No. 4 in Appendix B). At the conclusion of the Settlement Conference, ECMI, VECC, CAC, Hydro One, the EDA and Toronto Hydro supported the proposition, with some minor revisions. No other party opposed the revised proposition. However, many parties raised concerns about the possibility of gaming. Many parties also raised concerns about the potential for gaming under Hydro One's current approach, which has not been approved by the Board.

48 Hydro One's concerns that the CATC approach was contrary to the Market Rules and the *Electricity Act, 1998* appear to have been alleviated as a result of extensive discussions during the Settlement Conference.

49 The Board accepts the Settlement Conference outcome with minor modifications. In the revised Code, the transmitter will be required to complete an expansion study and determine a CATC entitlement for each of the transmission customers connected to a Connection facility whenever the total load on that Connection facility is approaching the maximum normal planned supply capacity of the Connection facility.

50 The Board notes that the methodology to be used by transmitters in the determination of maximum normal planned supply capacity will be considered in Phase 2 of the Proceeding. For a load customer who has a contract, freely entered into between the transmitter and its customer to serve the customer's load, the CATC is the load level used in the customer load forecast included in the economic evaluation of that contract. For existing customers, with no explicit contract with the transmitter, the CATC will be calculated using the average of 3 consecutive months of highest peak load in the most recent 5 years for the transformer station or feeder position(s) or Line Connection facility, whichever is more appropriate. Each CATC determination will consist of a typical usage pattern (e.g., 24-hour typical load shape) and will be made on a per delivery point basis. A customer will always be assured of this baseline allocation of capacity. Each customer's baseline will be determined using the 5 years prior to the connection facility expansion study.

51 The calculation of CATC shall not include anomalous situations such as temporary load transfers, emergency situations or any transmission reconfigurations that may be required by the IMO. The Board is of the view that capacity is not to be allocated for back-up purposes, in recognition of the concern raised by ECMI. Allowing all load customers to reserve substantial amounts of Connection capacity for contingency purposes would result in an economically inefficient use of the transmission system, leaving much of the system unutilized for the majority of the time.

52 Designating CATC with different attributes and special financial considerations would also introduce unnecessary complexities. CATC shall only reflect normal operating conditions.

53 The Board finds that Available Capacity on a particular Connection asset will be determined by subtracting the total CATC for all connected customers from the total maximum normal planned supply capacity of the Connection facility, with due regard to diversity among loads. No time-limit shall apply to a customer's CATC. In addition, and in accordance with the concerns raised by a number of parties, the Board confirms that the CATC approach does <u>not</u> apply to Network assets.

54 The CATC determinations for a particular Connection asset are to be made available to all parties connected to that Connection asset, in a manner that is consistent with confidentiality requirements.

55 The Board is of the view that the use of 3 consecutive months as opposed to a single month peak for the calculation of CATC will make it more difficult for a customer to manipulate its determination of CATC. Such manipulation will be prohibited in the Code. Where parties are found to be manipulating their determination of CATC, the Board may review and redetermine an appropriate CATC for the customer and the Board may also impose penalties.

56 The CATC is associated with a Connection facility. As a result, where a transmission customer enters into a financial transaction that results in a change of business ownership, the CATC associated with the seller's existing connection facilities will not be affected. The CATC will be automatically transferred to the purchaser of the business upon completion of the transaction. Any party purchasing a facility from an existing customer should investigate all aspects relating to the connection agreement including, if applicable, the CATC entitlement on the applicable Connection facilities.

57 Where there is agreement between the transmitter and the transmission customer that the CATC requires an adjustment, or a dispute arises between the transmitter and the customer regarding the CATC determination, the parties should seek direction from the Board.

58 The Board is of the view that different measures for calculating CATC, as proposed by Imperial, are not necessary, given the changes to the CATC approach that the Board has adopted herein. Imperial's primary concern was the use of the single highest monthly 5-year peak. As discussed above, the Board has decided against the use of a single monthly peak in favour of the average of three consecutive months.

59 The parties supporting the modified CATC definition at the Settlement Conference expressed a strong desire that the CATC be defined only for the purpose of allocating existing capacity in relation to an expansion of a Connection facility. The Board is of the view that the methodology used in the CATC calculation should not be restricted in its use because it is also an appropriate method to distinguish between new and existing load.

4.4 AVAILABLE CAPACITY - BOARD PROPOSITION NO. 4.4

60 *The Code should establish the principle of first-come, first-served in the allocation of Available Capacity, but with some modifications and qualification as discussed in Board propositions No. 4.5 and No. 4.6 below. An applicant must clearly document the future need that gives rise to the request. Available Capacity should not be allocated on the basis of vague or unsubstantiated statements about future needs.*

4.4.1 Analysis and Findings

61 Generally, there was no opposition to this proposition. Hydro One supported the "first-come, first-served" principle on the basis that it is consistent with Hydro One's current methodology, as well as the legislative requirement to provide non-discriminatory access. However, Hydro One submitted that the CATC approach is not based on the "first-come, first-served" principle. Hydro One interpreted the "first-come, first-served" principle to mean that Available Capacity is given to any incremental load that needs it and is not reserved for future use by existing customers. Hydro One agreed with the need for a customer to clearly document its future needs. Responsibility for the load forecast should reside with the customer, who is in the best position to determine its needs. It was Hydro One's view that customer accountability for load growth projections will lead to better decisions regarding need. If Available Capacity is allocated, but the load does not materialize, the capacity should be made available to other customers on a "first-come, first-served" basis.

62 ECMI submitted that the first-come, first-served principle should be applied to Available Capacity on a Connection facility, provided that existing customers connected to that Connection facility are contacted. ECMI also suggested that nearby customers, currently connected to other Connection facilities but who may be able to be supplied by that Connection facility, should be given an opportunity to use such Available Capacity.

63 The Board does not see any inconsistency between the CATC approach it has adopted above and the "first-come, first-served" principle to be applied to Available Capacity. The CATC approach merely establishes the genuine load requirement existing at the subject Connection facility. Available Capacity is not meant to be reserved, and nothing in this Decision should be construed as having that effect. It is to be allocated on a "first-come, first-served" basis to customers who can demonstrate a need for it.

64 The Board accepts the point made by ECMI that existing customers connected to a Connection facility should be notified of any request made for Available Capacity on that Connection facility, since the allocation of Available Capacity has the potential to affect them. However, ECMI has not demonstrated any practical method by which a transmitter could notify adjacent customers connected elsewhere who might be in an overlapping supply zone between two Connection facilities.

65 Accordingly, the principle of "first-come, first-served" for the allocation of Available Capacity shall be applied in the revised Code, subject to the CATC criteria set out in section 4.3.1. Available Capacity will not be allocated to a customer until the customer can clearly establish and document its future need. There will be a requirement for the transmitter to notify all existing customers connected to the same Connection asset when there is a request for Available Capacity. The issue of what should happen to allocated capacity if the load does not subsequently materialize is addressed in section 4.6 below.

4.5 AVAILABLE CAPACITY - BOARD PROPOSITION NO. 4.5

66 *The Code should contain provisions governing the allocation of Available Capacity among various participants competing for the Available Capacity in Line or Transformation Connection facilities. These provisions should reflect the goal of achieving allocations that are as economically optimal as possible. An example of this occurs when distributors are competing for Available Capacity that exists in a transformer station owned by a transmitter.*

4.5.1 Analysis and Findings

67 Hydro One is in agreement that the Code should reflect the goal of achieving allocations that are as economically optimal as possible. No other party opposed the proposition. The Board adopts the proposition as stated above for the purposes of the revised Code. Further detail is provided in sections 4.6 and 4.7 below.

4.6 AVAILABLE CAPACITY - BOARD PROPOSITION NO. 4. 6

68 *All allocations of Available Capacity should be time-limited and non-assignable. The Board believes this would help to achieve an allocation of Available Capacity that is as economically optimal as possible. It would also mean there would be no secondary market for Available Capacity.*

4.6.1 Analysis and Findings

69 The issue underlying this proposition is whether there should be the possibility of a secondary market for Available Capacity. Hydro One agreed that all allocations of Available Capacity should be both time-limited and non-assignable. AMPCO recommended that Available Capacity be assignable when a load entity is sold. For example, an industrial plant purchaser would retain the Available Capacity that had been allocated to the plant prior to the purchase. AMPCO was of the view

that this would not lead to a secondary market. ECMI was of the view that the meaning of "time-limited" required clarification.

70 The Board is of the view that a one year time limit, from the date of the allocation, would be appropriate for all allocations of Available Capacity. If the allocated capacity is not taken up within a year, the transmitter would be free to reallocate it. If a customer who has been allocated capacity subsequently sells the business associated with the load, the original one year period will continue to run (i.e., not restart upon transfer), allowing the purchaser to take up that capacity to meet the load requirements of the business. It will be a matter of due diligence on the part of the purchaser to investigate the amount of time remaining associated with the allocated capacity, prior to purchasing the business. Allocated capacity is otherwise not assignable, to avoid the development of a secondary market. A customer may apply to the Board for an extension of the one year time limit where circumstances warrant such application, for example, where a customer is constructing new connection facilities that will require more than one year to put in service.

4.7 AVAILABLE CAPACITY - BOARD PROPOSITION NO. 4.7

71 *The process for managing Available Capacity should be transparent.*

72 *The Code should require the transmitter to maintain up-to-date and publicly available information about the Available Capacity on its Connection facilities subject to reasonable customer confidentiality concerns.*

73 *A request for an allocation of Available Capacity should trigger notification to all customers connected to the affected facility and a period should be allowed for other connected parties to submit a competing application for the Available Capacity. The Available Capacity will be divided fairly among those applicants that have adequately demonstrated a need.*

4.7.1 Analysis and Findings

74 Hydro One agrees that a process for managing Available Capacity should be clear to all market participants. Hydro One raises a concern that were it to be required to provide information about Available Capacity for future years it could be in violation of its licence conditions respecting confidentiality. This would arise, it suggests, because future Available Capacity is based on load forecasts, which is the kind of information it must protect. Hydro One asserts that, if future years' Available Capacity is to be published, confidentiality considerations need to be factored in to determine how information should be disclosed so that the transmitter is not violating its licence conditions. Hydro One also submitted that the transmitter should only be required to make available all relevant information on Available Capacity where there is a customer request.

75 The Board finds that the process for managing Available Capacity needs to be transparent. A request for an allocation of Available Capacity triggers a requirement for the transmitter to notify all customers connected to the affected Connection facility, as the Board has noted above in the proposition. A reasonable period shall be allowed for other connected parties to submit competing applications for the Available Capacity. Subsequently, the Available Capacity will be divided fairly among those applicants that have adequately demonstrated a need.

76 The Board agrees that a requirement to maintain publicly available information regarding the Available Capacity for all connected customers at all times is unnecessary and would impose a significant administrative burden on transmitters. Under the revised Code, the transmitter will only be required to promptly provide information about the Available Capacity of a Connection facility to all affected customers at the time of a proposed system expansion of the Connection facility or upon a customer's request for Available Capacity and any other such time that the Board determines to be appropriate.

77 The Board agrees with Hydro One that such information should be provided taking into account reasonable customer confidentiality concerns. Customer confidentiality concerns will likely be of greatest concern where there is only a single customer connected to a Connection facility and Available Capacity information needs to be made available to a potential new customer. In such cases, information regarding Available Capacity shall be made available only with the consent of both customers. Special consideration will need to be given to those situations where the prospective customer is a competitor of the existing customer. Such situations can be brought to the Board for direction. Where there is more than one existing customer connected to a Connection facility, information shall be aggregated by the transmitter to avoid confidentiality concerns.

4.8 AVAILABLE CAPACITY - BOARD PROPOSITION NO. 4.8

78 *Where a transmission customer can demonstrate that Available Capacity will not meet its needs for supply of new load, that customer should have the right to arrange for its own connection facility requirements. Where a transmission customer opts to build its own connection facilities, as opposed to using Available Capacity, those new facilities should only be used for the new load (i.e., the customer should not be allowed to transfer existing load from the transmitters' facilities). A customer may waive the right to construct its own connection facilities to serve new load as part of a contractual negotiation. In order to be effective and enforceable, such a waiver must be in writing, and should include a reference to the Section of the Code bestowing the right, and should stipulate that the Customer has waived the right voluntarily, and without undue influence or duress.*

79 *Where contracts entered into prior to the adoption of this provision contain restrictions on the customer's right to build its own facilities to serve new load, such restrictions shall be unenforceable.*

4.8.1 Analysis and Findings

80 Hydro One agreed that customers should have the right to arrange for their own connection facility requirements if Available Capacity will not meet their new load requirements. The determination of whether Available Capacity is adequate should be: (1) based on both local and system wide considerations; and (2) made jointly between the transmitter and customer, with disagreements subject to a timely dispute resolution process. Hydro One further submitted that a customer's new load must not be incremental load already included in the initial load forecast that led to the construction of the transmitter's Connection facility in the first place. If load in the initial load forecast is transferred to a customer's own connection facilities, this would constitute bypass of the transmitter's Connection facilities and would have an unacceptable negative impact on other Connection pool customers.

81 APPrO submitted that it is unworkable and unrealistic from an economic point of view to expect that a customer would split new load from old. Such a requirement would lead to uneconomic duplication of connection facilities. In its view, this issue needs to be resolved in conjunction with proposition 5.3 of the Transmission System Bypass section. Sithe supported APPrO's position.

82 OPG submitted that the principle of economic efficiency contradicts the proposed principle. When faced with the need to construct new connection facilities, a competitive firm will consider a full range of options that could include replacing the existing connection facility and transferring all existing load to the new connection facility. In part, economy of scale would suggest that a single, large new connection facility may have significant advantages over an incremental addition to an old outdated, and undersized one. Therefore, there should not be a specific prohibition against such transfers. To the extent that a transfer results in a stranded investment, the customer should pay for that cost based on a calculation to be detailed in the Code, which is based on the depreciated value of the asset minus any savings in the transmitter's O&M costs. In OPG's view, in such a calculation, the stranded cost should also be reduced to the extent that the transmitter would not have recovered the full asset value in the course of expected operations absent the action that caused the stranding. Brighton and TransAlta supported OPG's position. TransAlta submitted that as long as true and material stranding is compensated for properly, then duplication of assets could serve as an economically efficient competing alternative to a possibly inflexible transmitter-provided connection option. Transmitters understandably would like to retain monopolistic control over connection asset infrastructure. But, not only is there no "economic efficiency" penalty associated with competitive provision of the service, but such competition also usually leads to system-wide gains in economic efficiency.

83 With regard to OPG's suggestion that the customer should be given a credit for any reduction in O&M costs, CAC and VECC submitted that this would only be appropriate in situations where the customer had already pre-paid its O&M costs, as the current propositions suggest would be the case for generators (see Cost Responsibility proposition No. 4.6). Otherwise, the remaining transmission customers are effectively being required to pay the O&M costs for connection facilities the utility no longer owns, and to subsidize the operations of the individual customer concerned.

84 AMPCO submitted that the proposition should be extended to allow customers to construct their own connection facilities for some existing loads, when modifications are required, provided the customer reimburses the transmitter for the depreciated book value of any transmission assets that would be stranded. This position is very similar to that advanced by OPG and TransAlta.

85 Brantford Hydro submitted that the Board should recognize that some customers are overpaying when existing Connection facilities are operated on an overloaded basis. Switching is the only practical means by which a distributor can increase its peak, at a given delivery point, with a corresponding reduction at another delivery point. The overload portion of existing load should be transferable to new connection facilities without penalty.

86 The EDA argued that the Code should indicate that a customer's obligation to use a transmitter's Connection facilities terminates once those Connection facilities reach the end of their useful life, where the customer waived the right to construct its own connection facilities prior to the construction of the transmitter's Connection facilities. Toronto Hydro endorsed the EDA's position.

87 The method by which a transmitter might be compensated for assets that are stranded as a result of a customer building its own connection facilities was addressed at the Settlement Conference. Three options were examined and supported by various parties (see Appendix B - the Facilitator's Report -for a discussion of those options). Many parties advocated the use of Net Book Value ("NBV") as a basis for compensating transmitters in the event of Board approved bypass events. The transmitters expressed the view that the use of NBV is acceptable if the remaining asset life were adjusted by a methodology that focuses on dispersion analysis of transmission assets, commonly known as "Iowa State University Approach/Technique" or other appropriate annuity adjustments, to reflect the changed life expectancy of the asset at the time the valuation is being under-taken. The Board retained Navigant Consulting Inc. to prepare a report on this issue. The report was provided to the parties and they had an opportunity to make further submissions.

88 The Board has decided that the amount of Available Capacity will not be a factor when a customer makes its own transformation connection arrangements to serve its new load. However, a customer will be required to demonstrate that Available Capacity would not meet its needs with respect to Line Connection facilities. In the case of Line Connection facilities, the Board is concerned that Available Capacity be used first, otherwise it would likely result in parallel lines, requiring additional right-of-way and construction impacts. Under such circumstances there is a clear risk of uneconomic and unnecessary duplication. The revised Code will discourage unnecessary duplication.

89 The Board recognizes that a transmission customer may waive the right to construct its own connection facilities to serve new load as part of an agreement with the transmitter. To be effective and enforceable, such a waiver must be in writing and stipulate that the customer has waived the right voluntarily, without undue influence or duress.

90 In response to intervenor submissions, the Board reexamined the situation where a transmission customer opts to build its own transformation connection facilities, instead of using Available Capacity. These new customer transformation facilities may also be used to supply the customer's existing load if the customer adequately compensates the transmitter for the loss of that existing load. Having reviewed the Facilitator's Report from the Settlement Conference, the Navigant report and the subsequent submissions of the parties, the Board has decided that the most appropriate method is the NBV approach, including a credit for salvage and the addition of reasonable removal costs, which will include reasonable costs for environmental remediation. The Board has chosen this approach because it is objective and is consistent with the Board's approach to determining rate base for transmitters. In establishing the revenue requirement for transmitters in rate making Proceedings, the Board factors in equipment assets on a NBV basis. This means that the depreciated value of the equipment is captured in the rate-setting exercise. A number of parties were concerned that the adoption of the Iowa curves to adjust the calculation would impose costs which were not genuinely justified. They also expressed the view that the use of the Iowa curves introduced unnecessary complexity. They argued that the transmitter should have close at hand the depreciated values for equipment engaged in the compensation valuation. The Board agrees.

91 The Board acknowledges that equipment can, and often does have value and utility notwithstanding that it may be fully or substantially depreciated. Depreciation is a tool to account for the aging of equipment for accounting purposes, but it is not designed to precisely or specifically predict or establish the equipment's actual useful life. Insofar as the establishment of the appropriate compensation for stranded assets is a financial and not an engineering exercise, the use of NBV is most appropriate. It is important to note the fact that if equipment has been fully or substantially depreciated it ought not to create an inclination to replace equipment that still is viable and has residual useful life. Replacement of outdated equipment is an engineering exercise, and the prudent operator will not replace on the basis of NBV, but only on the basis of an assessment that takes into account appropriate asset management techniques to determine whether the equipment is at or near the end of its useful life.

92 The Board is of the view that reducing the stranded cost and the compensation owed to the transmitter, using the methodology proposed by OPG (i.e., to the extent that transmitter would not have recovered the full asset value in the course of expected operations absent the action that caused the stranding) would introduce an unnecessary complexity and also appears to be somewhat subjective. There was no support for this approach by any parties at the Settlement Conference.

93 The Board has decided that the NBV approach to compensation will be used for any bypass authorized by the revised Code.

94 The Board is of the view that with respect to the bypass of a transmitter's Transformation Connection facilities resulting from the transfer of existing load from such facilities to a transmission customer's transformation facilities, an issue arises where the transmission customer is a distributor. Similar to an end-use consumer connected to the transmission system, a distributor could compensate the transmitter to hold the transmission pool harmless. However, unlike an end use customer, this compensation could come at the expense of the distributor's captive retail customers. The Board requested that this issue also be addressed at the Settlement Conference. The outcome at the Settlement Conference was a consensus on a defined formal process, outlined in the Settlement Agreement (Appendix B, Issue No. 1), involving the distributor, transmitter and the Board. Under this proposed process, the Board should appoint a facilitator, at the cost of the parties, in circumstances where they are unable to resolve the issues. The facilitator would make recommendations and, where a dispute remains, the Board will initiate a proceeding culminating in a decision. Each party involved will be responsible for its own costs in the process.

95 The Board adopts this proposal, with some qualifications. First, the Board will not be subject to the specific time constraints identified. In addition, there will <u>always</u> be a prudence review, regardless of any agreement reached by the transmitter and distributor, which could result in some or all of the distributor's investment being disallowed in rates. The onus will be on the distributor to demonstrate to the Board that a new transformation station was, in fact, necessary to the continued prudent operations of the distributor, and that it was more cost-effective for the distributor to build it than to utilize the transmitter's existing transformation facilities.

96 There is one circumstance which would permit the transmission customer to build its own new connection facilities to serve existing load without compensating the transmitter. This circumstance arises where the existing Connection facilities are overloaded. The Board is of the view that the overloading of any Connection facilities reduces the economic efficiency of the transmission system and should be avoided, where possible. In such cases, only the overload portion of existing load shall be transferable to the new line or transformation connection facility without compensating the transmitter. Overload shall be defined as anything above the maximum normal planned supply capacity of the Connection facility.

97 The Board has decided that where contracts, entered into prior to the adoption of these provisions in the revised Code, contain restrictions on the customer's right to build its own transformation or line connection facilities to serve new load or the overloaded portion of existing load, such restrictions shall be unenforceable by the transmitter.

98 The Board does not share the view that requiring an existing customer to distinguish between new and old load is unworkable or unrealistic as was suggested. The Board has decided that the same methodology as outlined in section 4.3.1 above with respect to CATC shall be used to establish a customer's existing load level. For new customers, this CATC determination will be established by their load forecast and, accordingly, such customers will be held to that load forecast.

5. <u>TRANSMISSION SYSTEM BYPASS</u>

5.1 TRANSMISSION SYSTEM BYPASS- BOARD PROPOSITION NO. 5. 1

99 *The Code should contain a definition of "Embedded Generation" which addresses such factors as ownership, location and other relevant factors.*

5.1.1 Analysis and Findings

100 The issue of what constitutes Embedded Generation was addressed by the Board in RP-1999-0044, which was a Hydro One rates case. Whether generation is embedded in relation to a transmission customer affects how, and how much the customer is to be charged by the transmitter for transmission services. The issue was also addressed more recently in two subsequent proceedings, RP-2002-0143 and RP-2002-0118. Those proceedings dealt with complaints brought by transmission customers, each of whom asserted that Hydro One refused to recognize certain generators as embedded and therefore was billing the customers in a manner not consistent with the governing rate order. In each proceeding, the Board concluded that the generation in question was embedded because it was connected on the customer side of the point of connection between Hydro One and the transmission customer.

101 This Decision, however, looks at the issue more broadly to determine under what circumstances generation ought to be considered to be embedded, examining the various possible combinations of old and new generation with old and new load. The Board is of the view that a comprehensive definition of Embedded Generation will provide greater regulatory certainty, which should facilitate investment in desirable new supply. The determination as to whether generation is embedded in a variety of scenarios will affect how the transmitter charges its customer, as set out in RP-1999-0044.

102 The definition of Embedded Generation was one of the seven issues addressed at the Settlement Conference. The settlement discussions resulted in the development of two options, each supported by different parties. Appendix B (Facilitator's Report, Issue No. 4) provides a detailed description of the two options. There were several similarities between the two options.

103 For both options, there was consensus that the generation is embedded if it is connected behind the point of connection between the facilities of the transmitter and the transmission customer. This is consistent with the Board's conclusion in RP-2002-0143 and RP-2002-0118. There was also agreement that generation is embedded if the generator is connected directly to a distribution system. This is consistent with RP-1999-0044.

104 There was consensus, for both options, that the ownership of the generation, the voltage level at which the generator is connected, and the type of licence held by a customer are not relevant to the question as to whether generation is Embedded or not. This, too, is consistent with the RP-2002-0143 and RP-2002-0118 Decisions. There was also agreement that it was immaterial whether the Embedded Generation capacity was greater than or less than the customer's load.

105 The parties concluded, for both options, that a Board review process should be available to resolve disputes as to whether a specific generation facility should be treated as embedded where the generation asset and the load are connected to the same Line Connection facility owned by a transmitter. Recourse to the review process would not be required if the generation was renewable generation. In such circumstances, the renewable generation would be deemed to be embedded. The parties also agreed that if new generation met the criteria for Embedded Generation, it did not matter if that generation was connected to existing or new load. However, the options diverge in their proposed treatment of new or reconfigured connections between existing load and existing generation. Option 1 would make recourse to Board review available in all such circumstances where the parties were unable to resolve their differences, while Option 2 would not provide for such recourse where the situation involved new load connected to existing generation, which should be considered to be embedded.

106 In Option 1, where generation qualified as Embedded in relation to a load, there would be an automatic rate adjustment for the transmitter based on the removal of that load. CAC and VECC did not support this aspect of Option 1.

107 Option 1 required generation and load to be located on a single property, while Option 2 did not. Option 2 did not require a Board review process for generation with a capacity of less than 20 MW.

108 In the Settlement Conference, the IMO took the position that the emerging definition of Embedded Generation in these proceedings, which is used for the purposes of establishing transmission rates and the consideration of Code issues, appeared to be different than the definition used in connection with the Market Rules. The IMO was of the view that it may be impractical to try to reach a common definition of Embedded Generation for both rate making purposes and reliability and connection purposes as addressed by the Market Rules.

109 There are four possible combinations of generation and load which the Board considered in deciding the issue of what constitutes Embedded Generation for the purposes of the Code. These are:

* new generation - new load
* new generation - existing load
* existing generation - new load, and,
* existing generation - existing load.

110 The Board's approach is driven in part by the objectives of the Act as expressed in Section 2 thereof. In addition, the Board is mindful of the overall state of the electricity market in Ontario, and the importance of accommodating, to the extent appropriate under its statutory mandate, the introduction of new and expanded generation to meet existing and new demand.

111 The Board will address the first two combinations together, since they each involve new generation and can be reasonably dealt with in the same manner.

112 The Board recognizes that the transmitter may lose some revenue from existing load when such load is subsequently met by new Embedded Generation. It is reasonably predictable that the advent of new generation, including new Embedded Generation, will result in overall improvement and growth in the electricity market. Much of the loss of transmission revenue is likely to be reduced or perhaps totally offset by load growth in the market as a whole. The Board also recognizes that this may lead to some increase in the costs borne by transmission ratepayers, but this should be offset by the expected reduction in overall energy cost resulting from entry of new generation. New generation means there is more supply to meet peak demand which should reduce energy costs for all consumers. Ontario is currently facing a tight supply situation and has had to rely on expensive sources, including imports, from time to time to meet peak demand. Historically, Embedded Generation has tended to be in the form of cogeneration, which is a more energy efficient and cost effective form of generation than most merchant generation. Embedded Generation may also have the effect of enhancing reliability and reducing inefficiencies associated with transmission congestion.

113 The Board is of the view that to the extent that all ratepayers will benefit from lower energy costs and a more effective and efficient transmission system, it is appropriate for them to bear additional transmission costs that may result from the rate treatment set out in RP-1999-0044 for Embedded Generation.

114 The Board recognizes that the commercial realities of the market place are such that there will often not be common ownership of load and generation. The Board considers it to be important that the imagination and industry of the marketplace be permitted adequate scope to develop configurations and arrangements that will serve the important societal goal of enhancing the efficiency and effectiveness of the electricity supply system in Ontario. It would be an unnecessary barrier to new generation to require common ownership as a criterion for qualification as Embedded Generation. For similar reasons, it is not necessary to require that the load and the generation be located on the same property. While Embedded Generation is often located on the same property as the load customer, there is no reason that generation should not be considered embedded if it is located on separate property, provided that it is connected on the transmission customer side of the connection point/interface between the transmitter and that transmission customer.

115 Generation can be connected at transmission or distribution voltage. The choice is often driven by economic or system efficiency factors which ought not to affect the question of whether the generation is Embedded. That was the Board's view in the RP-2002-0143 and RP-2002-0118 Decisions and there is no reason to take a different approach for the purposes of the revised Code.

116 There are many commercial arrangements that can be entered into by new generators and new types of arrangements will occur as the Ontario electricity market continues to evolve. The Board does not believe that the form of commercial arrangement entered into by new generation should affect whether that generation is considered to be embedded. To do so would be to run the risk of creating barriers to new generation. This is consistent with the Board's approach in RP-2002-0143 and RP-2002-0118.

117 The Board recognizes it is possible that Embedded Generation capacity may exceed the related load. It would be inconsistent with the objective of ensuring a reliable supply of electricity for Ontario to limit Embedded Generation capacity to the size of the load. Similarly, the number of generating units ought not to be a factor in determining whether new generation is Embedded.

118 The Board therefore finds, for the purposes of the revised Code, any new generation that is connected on the customer side of the connection between a transmission customer and the transmitter will be considered embedded, and therefore not transmission system bypass, regardless of:

* whether the customer load is new or existing;
* who owns the generation;
* where the generation is located;

* what voltage the generation is connected at;
* what commercial arrangements the generator enters into; and
* the size or the number of units of generation capacity.

119 For the purposes of the revised Code, the Board is of the view that the appropriate date to distinguish between new and existing generation shall be the date that this Decision is published on the Board's web site. This means that any generation facilities which go into online operation on or after the date that this Decision is published will be considered to be new. This does not affect any Board Decisions made in RP-1999-0044 and, as a result, October 31, 1998 will continue to be the date used for the application of rates under the current rate order.

120 If new generation is Embedded in relation to a load customer, the transmitter will charge for transmission services in accordance with the RP-1999-0044 Decision.

121 The revised Code will not provide for an automatic rate adjustment for the transmitter when load is lost as a result of new Embedded Generation, as proposed in Option 1. The Board prefers not to address one narrow aspect of what constitutes just and reasonable rates in isolation. Transmission rates are best addressed in a rates proceeding which looks at all rates issues together and establishes just and reasonable rates.

122 The Board will address the last two combinations together since they both involve existing generation.

123 It is possible that by reconfiguring existing transmission system connections, existing generation can become embedded in relation to an existing transmission customer. Similarly, new load can be connected in such a way that existing generation can be Embedded in relation to that new load. The Board is not prepared to consider either combination as Embedded Generation for the purposes of RP-1999-0044.

124 Reconfiguration may result in narrow benefits for the generator or associated load customer but there is no apparent benefit to ratepayers who will bear the cost of assets that are stranded as a result of reconfiguration, primarily because no new generation has been added. Such reconfiguration amounts to bypassing the transmitter, which will increase the cost to be borne by other ratepayers unless the transmitter is compensated for the bypass.

125 In the revised Code, the Board will not consider any reconfigured existing generation to be Embedded for the purposes of RP-1999-0044 and gross load billing will, therefore, apply for both Network and Connection charges.

126 The Board emphasizes that for new Embedded Generation situations that are consistent with the revised Code, the bypass of transmitter-owned existing Transformation and Line Connection facilities serving existing load customers is allowable. If the bypass results in reduction of usage of the connection facilities, as set out in RP-1999-0044, the transmitter will be billing the customer on a gross load basis for the relevant Connection assets. However, if the existing customer(s) disconnects from the transmitter's Connection assets to take service from a new and, in effect, duplicative line and transformation connection owned by a party other than the transmitter, the transmitter's Line Connection and Transformation Connection assets, as the case may be, would be stranded, but the transmitter would not be compensated through gross load billing as the Board envisioned in RP-

1999-0044. As a result, in such cases of bypass, the compensation for these Connection facilities will be a responsibility of the customer(s), and would be based on the NBV of the stranded assets.

127 As a result of these findings, a Board review process, as set out in the Facilitator's Report, is not necessary. It is also not necessary to consider the establishment of the Local Interrelated System concept as discussed at the Settlement Conference.

5.2 TRANSMISSION SYSTEM BYPASS- BOARD PROPOSITION NO. 5. 2

128 *The Code should reflect the principle with respect to the rate treatment of new Embedded Generation (i.e., net billing for Network and gross billing for Connection) established in RP-1999-0044.*

5.2.1 Analysis and Findings

129 Hydro One agreed with and supported RP-1999-0044. Generators agreed that rate treatment should be aligned with the principles established in RP-1999-0044. Large consumers submitted that net load billing for both Connection and Network charges should be applied in a manner consistent with the principles established in RP-1999-0044. The EDA generally supported the same proposition. In addition, the EDA suggested that the revised Code should include a specific clause to the effect that transmission load displaced by Embedded Generation of 1MW or less ought not to be considered system bypass. CAC and VECC submitted that there is a potential conflict with Proposition No.5.4, below, and that gross load billing could be viewed as a measure that discourages the development of Embedded Generation. In their view, Proposition No. 5.2 should take precedence over Proposition No. 5.4.

130 In order to ensure consistent rate treatment, the Board is of the view that transmission customers with new Embedded Generation, as defined in this Decision, will be subject to the rate treatment established in RP-1999-0044. That is, net load billing for Network charges and gross load billing for Connection charges, except for Embedded Generation of 1 MW per unit or less where net load billing applies for both Network and Connection charges. The Board will increase the qualifying limit for exemption from gross billing from 1 MW per unit to 2 MW per unit for renewable generation installations. This increase reflects a societal interest in increasing the proportion of renewable generation in the overall generation mix in the province, and the technical reality that the output of some renewable source generation equipment has advanced from under 1 MW per unit to just under 2 MW per unit. It is intended that renewable energy projects comprised of generation units producing 2 MW or less per unit will be eligible for net billing charges on relevant connection facilities. The Board notes that there was a request to increase this qualifying limit to 20 MW. The Board rejects this proposal as being excessive.

131 There are references to "cleaner" energy sources throughout these propositions. There was a general consensus amongst the parties that this terminology was ambiguous, undefined and should be replaced with "renewable" energy sources. The Board agrees. The parties involved in this process also agreed to a definition of "renewable energy sources" as set out in the Facilitator's report. However, the Board believes it would be prudent to use an existing definition of renewable energy, as developed by the Ontario Government, to avoid having competing definitions in the Ontario electricity market. The Government recently released its Request for Qualifications (RFQ) for 300 MW of new renewable capacity. That RFQ contained such a definition which states that: *a "Renewable Generating Facility" refers to a facility that generates electricity from the following sources: wind,* *solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water.* As such, the Board has decided to adopt this definition for the purposes of the revised Code.

5.3 TRANSMISSION SYSTEM BYPASS- BOARD PROPOSITION NO. 5. 3

132 *The Code should contain provisions establishing the right of load customers to construct their own connection facilities (e.g., transformation stations) regardless of the existence of Available Capacity, provided that the new facilities are designed to meet needs created by the development of new loads that are not presently served by existing transmission Connection facilities. The construction of such facilities should not be considered bypass. New load is defined as load which exceeds the CATC and based on the greater of either:*

> *1. the highest monthly peak load over the past 5 years for the relevant delivery points; or*
>
> *2. the Available Capacity of the existing feeder positions associated with the relevant delivery point.*

5.3.1 Analysis and Findings

133 This proposition is related to and follows from the propositions that were addressed in sections 4.2 in 4.3 above in the chapter dealing with Available Capacity. As the Board has indicated above, a transmitter shall not have an automatic entitlement to serve new load on its own Connection facilities.

134 The Board has decided that the revised Code shall contain provisions establishing the right of load customers to construct their own transformation connection facilities, regardless of the existence of Available Capacity, provided that the new facilities are needed to meet the new load. This right also applies to overloads on existing Transformation and Line Connection facilities, but only to the extent of the overload portion of the customer's load. The construction of such facilities shall not be considered bypass. In section 5.5.1, the Board addresses situations covering customers' existing load on transmitter-owned transformation connections.

135 The Board clarified that for line connection facilities, a customer will have to demonstrate that it has new load that cannot be met by the Available Capacity on the transmitter's existing Line Connection facilities, before it can construct its own line connection facilities, except where it involves overloaded Connection facilities. Where Available Capacity is not adequate, that customer shall have the right to meet its own line connection requirements and the construction of such facilities shall not be considered bypass. The rationale for this approach to line connection facilities is to ensure that there will not be unnecessary duplication of existing lines.

136 The rationale underpinning this approach is the Board's interest in creating opportunities for enhanced competition in the provision of construction and consulting services for connection facilities. Competition should be applicable where the system as a whole cannot reasonably be said to be compromised or unduly disadvantaged by such diversity. In the Board's view, such competition should result in an overall enhancement and optimization of the transmission system, and the creation of appropriate new business opportunities for other sectors of the economy.

5.4 TRANSMISSION SYSTEM BYPASS- BOARD PROPOSITION NO. 5. 4

137 *The Code should contain provisions which establish that the development of new Embedded Generation should not be considered to be system bypass. Any measures that discourage such development should be prohibited and where such measures are in existing agreements they should be unenforceable.*

5.4.1 Analysis and Findings

138 Hydro One generally agreed with the proposition. However, Hydro One also submitted that prohibiting measures that discourage Embedded Generation could lead to the construction of Embedded Generation that is justified solely on the strength of avoiding transmission charges (i.e., uneconomic bypass) and that this would be an inappropriate market signal which could discourage the development of more efficient forms of generation from a societal perspective. Hydro One submitted that this could result in higher transmission rates for remaining customers and the potential stranding of significant parts of the transmission system.

139 Generators were in agreement with the proposition. TransAlta objected to the inclusion of a "no bypass" clause in its existing Connection and Cost Recovery Agreement ("CCRA") with Hydro One, which TransAlta signed under protest. OPG in a separate application dated March 4, 2002, made requests including removal of a "no-bypass" section from Hydro One's CCRA template agreement. The generators stated that any existing contract that is inconsistent with the new Code should be amended to come in line with the revised Code.

140 GEC, CIELA and OSEA submitted that load reduction should also be excluded from the definition of bypass.

141 Large consumers agreed with the proposition, which is consistent with RP-1999-0044. AMPCO further submits that transmitters should not be able to circumvent RP-1999-0044 through additional contractual provisions.

142 Distributors were generally supportive. Generation supplying new load should not be considered bypass, but the Code should state that existing load displaced by Embedded Generation greater than 1MW per unit is to be considered bypass. The Code should contain criteria for calculating the gross load bill as a result of bypass. Bypass contributions should be reduced to the extent that:

* displaced transmission Connection assets have reached the end of their useful life;
* displaced capacity is built back by new transmission customer load growth;
* displaced capacity is reallocated by the transmitter to supply another customer; and
* the Embedded Generation is down at the time of the billing peak in a particular month.

143 CAC and VECC submitted that Proposition No. 5.2, above, should take precedence over Proposition No. 5.4. CAC and VECC further submitted that the Board should clarify that the reference to "system bypass" in the first sentence relates specifically to Network system bypass, and that the second sentence does not preclude gross billing for Connections. CAC and VECC also requested clarification that the second sentences in Propositions 5.4 and 5.6 do not preclude measures designed to achieve a balance between transmission system integrity and encouraging new generation or energy conservation or efficiency.

144 The Board notes that, generally, there was consensus that the revised Code should state that the development of new Embedded Generation, consistent with section 5.2 of this Decision, is not considered to be system bypass. To a large degree, this issue has already been addressed in section 5.2 Transmitters should not do anything that would discourage the development of new Embedded Generation. To the extent that provisions in existing agreements between a transmitter and customer prevent or discourage the development of new Embedded Generation or treat it as bypass, the revised Code will provide that such provisions are not to be enforced by the transmitter. The Board reiterates that load customers with Embedded Generation are to be billed in accordance with RP-1999-0044 as discussed above in section 5.2.1.

5.5 TRANSMISSION SYSTEM BYPASS- BOARD PROPOSITION NO. 5. 5

145 *The Code should contain provisions that would require transmitters to replace Connection facilities that have become fully depreciated at no charge to the customers served from that facility. The Code should, however, allow customers to construct their own connection facilities to replace transmitter's assets which have been fully depreciated and are, therefore, not considered to be stranded. If the Connection facilities serve more than one customer, the same rule applies. If, in this situation, some of the customers choose to remain with the transmitter's Connection pool, the transmitter will provide for appropriate new facilities at no charge to these customers.*

5.5.1 Analysis and Findings

146 Transmitters disagreed with the proposition. Hydro One submitted that it ignores the fact that facilities are built to accommodate future load and continue to be used and useful beyond their accounting life, and that the transmitter will continue to operate and maintain the facility, and include the costs in its cost of service. Value does not depreciate uniformly over time as components age and it is inconsistent with the principles of depreciation accounting. Depreciation rates are established on a pool basis to recover capital costs over the average life of assets; if some assets are prematurely abandoned, then depreciation rates and, consequently, transmission rates increase. In Hydro One's view, it would be incompatible with the current uniform rate structure and would also represent a move towards asset-specific pricing, increasing inequities among customers connected to newer facilities and those connected to older facilities. Hydro One further submitted that if bypass is allowed at the end of accounting life, then assets that fail prior to their accounting life should be replaced by the customer served by those assets, at their own cost. Hydro One proposed that the Code should permit bypass only at the end of an asset's physical life, as currently provided.

147 GLPL interpreted the proposition to mean that a transmitter would not charge a customer who is connecting to a fully depreciated Connection facility and that the transmitter must replace such facilities at no charge to a customer. GLPL disagreed with this proposition because the asset may still be serviceable. It argued that transmitters cannot be expected to replace Connection facilities for free and that it is inefficient to allow a customer to build its own connection facility to replace a transmitter's still useful, but fully depreciated, Connection facility.

148 Generators were generally supportive of the proposition. APPrO submitted that the Code should allow customers to buy down the remaining value of assets that are substantially depreciated in appropriate circumstances. OPG supported protecting customers from new stranded costs brought about by the transmitter's rebuilding of Connection facilities that have reached the end of their life, but in its view, the language used was problematic. OPG further submitted that the transmitter should not be required, or permitted to replace a facility solely because it is depreciated, as this is unlikely to match the end of the facility's operating life.

149 Large consumers agreed with the proposition. AMPCO submitted that the replacement of facilities by the transmitter at the transmitter's cost or replacement by the customer at the customer's cost should be at the customer's choice. The Code should include an allowance for cases where the Connection facility is substantially depreciated, such that the customer would have the option of reimbursing the transmitter for the remaining value of the assets. Imperial submitted that the Code should allow customers to construct their own connection facilities to replace a transmitter's assets which have been fully depreciated and are, therefore, not to be considered stranded.

150 The EDA was generally supportive of the proposition. The EDA further submitted that the transmitter should disclose to what extent existing facilities have reached the end of useful life and the revised Code should include a predefined methodology or standards for calculating the end of useful life. ECMI noted that the proposition appears to permit bypass only where Connection assets have been fully depreciated and to require the replacement of Connection facilities once they have become fully depreciated, not recognizing that assets may be serviceable long after they are fully depreciated. Reconstruction by the transmitter should only be required if the customer does not wish to purchase or construct alternate transmission capacity.

151 CAC and VECC submitted that to ensure a proper comparison between the cost of continued ownership by the transmitter and ownership by the customer, the transmitter must be allowed to undertake an economic evaluation and charge for the new facilities. It is inappropriate that customers be allowed to buy down the remaining net book value in situations where the assets are not fully depreciated.

152 ECAO submitted that customers should be permitted to replace depreciated assets with their own assets as a way to bring about greater competition and efficiency in connection activities. Customers are more likely to choose to take responsibility for assets, and only replace them when appropriate, rather than to duplicate assets.

153 Enbridge and Union Gas submitted that the Code should clarify that, while customers may not be directly charged for the replacement of fully depreciated Connection facilities, the costs will be included in the rate base and recovered from all customers. The Code should also indicate that replacement is required when assets are no longer capable of providing safe and reliable service and not automatically as soon as they are fully depreciated.

154 The Board agrees that Connection facilities should only be replaced by a transmitter if they have reached the end of their useful life, even if they have been fully depreciated. The Board recognizes that within a group of assets, different assets will have different actual lifespans, even though as a group, they are depreciated at the same rate. Some assets will require replacement before they have been fully depreciated, while others will still be useful even though fully depreciated. Such replacement should be at no cost directly to any individual customer, recognizing that the replacement assets will be included in rate base and subject to depreciation. The obligation to replace Connection facilities that are at the end of their useful life includes an obligation to ensure that Connection facilities are properly repaired and maintained on an ongoing basis, to ensure that they perform at the required technical standards and level of reliability.

155 The Board has decided that where a transmitter's Connection assets have been fully depreciated, the revised Code shall allow a customer to construct its own connection facilities, at the customer's own cost, to replace the transmitter's Connection assets. This does not constitute bypass since the transmitter's Connection assets have been fully paid for, and accounted for in the rate structure. If the Connection assets serve more than one customer, the same rule applies. In this situation, if some of the customers choose to remain connected to the transmitter's facilities, the transmitter will continue to have an obligation to replace the Connection facilities at the end of their useful life, at no charge to those customers, taking into account that less capacity is required to serve those remaining customers.

156 The Board finds that the determination of whether the Connection facilities have become fully depreciated shall be based on the NBV of those facilities. Where the NBV of a particular Connection facility, serving existing load, is greater than zero, a customer will not be permitted to construct its own connection facilities to supply that existing load, unless it involves a transformation facility, as this would constitute bypass. Where it does involve a transformation facility, the transmitter shall be compensated as outlined above in section 4.8.1 in the Chapter dealing with Available Capacity.

157 The underlying rationale for the Board's view is its interest in providing reasonable opportunities for new approaches to system change, so long as existing customers and the transmitters are not unduly prejudiced. By allowing customers a new range of options and introducing increased diversity in the development of new transmission connection assets within the system, the Board expects to see overall optimization. The approach of using NBV is consistent with the rate structures governing the transmission assets and incorporates them directly in the determination as to whether bypass is in fact being effected.

158 It is important to clarify that the fact that a transmission asset may have been fully or substantially depreciated is not of itself an adequate rationale for its replacement. Assets should only be replaced at the end of their useful life according to the transmitter's asset management program. These programs normally include an engineering determination of when an asset is no longer reasonably capable of providing safe and reliable service. Premature replacement should be considered to be imprudent.

5.6 TRANSMISSION SYSTEM BYPASS- BOARD PROPOSITION NO. 5. 6

159 *The Code should contain provisions which establish that reductions in load attributable to measures for energy conservation, energy efficiency, load management or use of cleaner energy sources should not be considered system bypass. Measures discouraging such activities, such as a transmitter imposing a minimum payment obligation to cover present loads, should be prohibited and where such measures are in existing agreements they should be unenforceable.*

5.6.1 Analysis and Findings

160 Hydro One generally agreed with this proposition, provided that there was no subsidization by the transmission ratepayers. Hydro One noted its concern, referenced elsewhere in this Decision, regarding "unenforceable terms". Specifically, it submitted that existing agreements should not be changed or affected without the consent of both parties. Hydro One argued that any resulting revenue shortfall to be absorbed by the transmission system pool should be recoverable by the transmitter in rates.

161 Generators agreed that load reduction in any form should not be considered bypass. However, generators were also of the view that "cleaner energy sources" is an ambiguous term and that the Code should not distinguish between generation fuel types on the basis of whether they are"cleaner generation sources", especially without a definition of "cleaner energy source" in the Code.

162 Large consumers were in agreement with the proposition.

163 The EDA was generally supportive of the proposition but suggested replacing "cleaner" with "renewable" or defining "cleaner" in the Code.

164 CAC and VECC submitted that clarification of what is meant by the term "cleaner energy sources" is required and that RP-1999-0044, with respect to cost allocation and rate design for transmission rates, clearly established a 1 MW limit for net billing on Connection facilities associated with Embedded Generation regardless of the source of the generation concerned. In the view of CAC and VECC, the 1 MW limit should apply equally to all types of Embedded Generation.

165 Enbridge and Union Gas submitted that the Code should establish that Embedded Generation and load reductions attributable to energy efficiency, energy conservation, load management or the use of cleaner energy sources are not system bypass. However, a broad prohibition against minimum annual charges should not be instituted, as these charges protect existing customers and shareholders from stranded facility costs. The Code should not inadvertently prohibit the use of Lost Revenue Adjustment Mechanism accounts, which are intended to protect the utility against losses in revenue as a result of demand side management ("DSM") initiatives. DSM initiatives provide a system benefit and customers are required to pay for the forgone margin revenue that results from energy conservation measures initiated by the utility. If minimum load payments are prohibited and unenforceable, transmitters should not be prohibited from recovering legitimate costs as approved by the Board.

166 The Board is of the view that reductions in load, attributable to energy conservation, energy efficiency, and load management, should not be considered system bypass, under any circumstances. The promotion of energy efficiency and conservation is one of the objectives of the Act and is particularly important at a time when Ontario faces a tight supply of electricity. There appears to be consensus that the Ontario electricity market requires increased demand response and conservation measures, and many initiatives are underway to facilitate achievement of that goal.

167 The Board is of the view that it is particularly important to ensure that the Code does not contain or create any barriers or disincentives for energy efficiency and conservation initiatives.

168 As indicated under Principle No. 8 and Principle No. 9 in Chapter 2, the Board has decided to replace "cleaner" energy sources with "renewable" energy sources. The definition of renewable energy sources is included in section 5.2.1 and the Board's decisions regarding the treatment of renewables is included in section 8.9.1 of this Decision.

169 The Board has decided that practices or measures which discourage such initiatives, such as a transmitter imposing a minimum payment obligation to cover present loads, shall be prohibited and, where such measures are in existing agreements, they shall be unenforceable by the transmitter. Where measures in existing agreements are determined to be unenforceable, such agreements shall be read so as to be consistent with the revised Code. Any terms contained in such agreements which are not in conformity with the Code, shall be unenforceable by either party to the contract.

6. COST RESPONSIBILITY

6.1 COST RESPONSIBILITY- BOARD PROPOSITION NO. 6.1

170 *The Code should establish the principle that Network costs incurred in establishing new or enhanced connections for load customers should be borne by the Network pool. Similarly, Network costs to connect new generation should be borne by the Network pool. The Code should allow for exceptional situations for a party to seek a different allocation of specific Network costs from the Board.*

6.1.1 Analysis and Findings

171 Transmitters generally agreed with Board's preliminary proposition. Hydro One's support was conditional on Board review being available for exceptional situations such as when a new generator causes an increase in transmission congestion, as a result of where it is connected to the transmission system. GLPL suggested that this proposition should be broader in scope to include Network costs incurred in establishing new or enhanced interconnections between transmitters.

172 Generators generally sought additional detail with respect to what constitutes "exceptional circumstances". They wanted a measure of certainty or predictability as to what cost allocation principles would apply in "exceptional circumstances". They took the position that the transmitter should not be the final arbiter of what constitutes exceptional circumstances and that there should be a requirement on the transmitter to identify exceptional circumstances prior to project development. They also submitted that exceptional circumstances should be considered in the broader context of potential implementation of locational marginal energy pricing and related transmission rights regimes in Ontario. Brighton stated that "Network" was not currently defined in the Code and a definition would be helpful. Brighton proposed the following definition of "Network" as set out in Appendix "B" to the Board's Procedural Order No. 1. Network means "the integrated part of the Ontario high voltage transmission system that is shared by all users, comprised of the network stations and the interconnecting 500 kV, 230 kV and 115 kV lines."

173 AMPCO supported the proposition, pending a thorough review of who should be responsible for transmission planning and the cost of transmission additions.

174 ECMI disagreed with the proposition, and advocated Board supervision in all cases. Toronto Hydro agreed with the proposition and opposed any attribution of Network costs to a new connection customer.

175 CAC and VECC submitted that in circumstances where Network reinforcement or other forms of investment are necessary solely as result of a new customer connection, then that customer should be held accountable for some, if not all, of the costs.

176 The IMO proposed the establishment of a stakeholder task force to develop a set of guiding principles to identify for inclusion in the revised Code those situations that would be an exception to the general principle that the cost of improvements to the Network are borne by all transmission ratepayers. This would include defining the respective roles of the various involved parties, including the IMO and the Board, and developing rules governing financial contributions by new customers for Network improvements.

177 In RP-1999-0044 and the existing Code, the Board established the principle that Network costs incurred in establishing new or enhanced connections for load customers, or to connect new generation, should be borne by all ratepayers since Network assets primarily benefit all Ontario electricity consumers. Accordingly, the Board reconfirms that principle for the purposes of the revised Code.

178 The Board recognizes, however, that there may be exceptional circumstances where it is more appropriate to allocate some or all of such costs to a transmission customer. Parties may apply to the Board to seek a different allocation of specific Network costs, based on the exceptional circumstances of a particular new connection. The issue raised by such an application is primarily one of rates and comes down to whether specific costs associated with Network improvements are to be borne by transmission ratepayers in general, in accordance with the general rule, or, in exceptional circumstances, by a particular customer. The Board would expect that such applications would be brought primarily by transmitters or transmission ratepayers. It is a futile exercise to attempt a precise definition of "exceptional circumstances". Parties should be guided by the principle that a specific customer should expect to be burdened with a specific allocation of Network costs only in circumstances where the project in question serves the interest of that customer, and results in material inconvenience or inefficiency to the Network as a whole. Creation of material increased congestion may be considered to be a possible exceptional circumstance, giving rise to a contribution from the customer causing the same.

179 With regard to the IMO's proposed task force to develop guidelines for exceptional situations, the Board believes that individual review on a case-by-case basis is more effective due to the expected complexity of such situations.

180 For the purposes of the revised Code, "Network" will be defined as "the integrated part of the Ontario over 50 kV high voltage transmission system that is shared by all users, comprised of the Network stations and the transmission lines connecting these Network stations."

6.2 COST RESPONSIBILITY- BOARD PROPOSITION NO. 6.2

181 *The Code should require any transmission load customer to notify the transmitter as soon as practicable, of any material reduction in load that will result from the introduction of new or increased Embedded Generation, energy conservation, energy efficiency, load management measures, or use of cleaner energy sources.*

6.2.1 Analysis and Findings

182 Hydro One generally agreed with this proposition, but pointed out that customers are generally not in a position to determine if a reduction in their load is material in terms of its impact on the transmission system, and therefore any proposed or planned reduction in load should be reported to the transmitter. Hydro One also pointed out that worker safety and equipment protection could be at risk if the transmitter is not contacted when a customer makes a change to its operations.

183 APPrO was concerned about the potential for duplication of reporting obligations to the transmitter as well as the IMO.

184 The EDA advised that where there is difficulty in gathering the required detailed information, the distributor may use variances in the associated delivery point load profiles to supplement specific information received.

185 The IMO indicated that Chapter 4, section 7.1.2 of the Market Rules already requires a market participant that "becomes aware of any material change to or inconsistency with any information or data previously supplied to another market participant or to the IMO in accordance with a new or modified connection that could affect the reliability of the IMO-controlled grid [to] promptly notify the IMO and such other market participant in writing of that change or inconsistency." The IMO further stated that the proposition to be reflected in the Code should be consistent with the obligations imposed by the Market Rules.

186 The Board is of the view that it is important for a transmitter to have notice of load reductions resulting from Embedded Generation, energy conservation, energy efficiency, load management measures, or use of renewable energy sources as early as possible. These are all initiatives that would require planning on the part of a customer and so it is not unduly onerous for a customer to notify a transmitter in advance of implementation. Accordingly, the revised Code will require that any Connection Agreement between a transmitter and a load customer shall include an obligation that the customer notify the transmitter, as soon as practicable, of any reduction in load that will result from the introduction of new or increased Embedded Generation or from energy conservation, energy efficiency, load management programs, or use of renewable energy sources.

6.3 COST RESPONSIBILITY- BOARD PROPOSITION NO. 6.3

187 *The Code should require that costs attributed to new or upgraded Connection facilities to meet the needs of a load customer or generator be allocated to that load customer or generator. Where more than one customer requests enhancements, all requesting customers should share the cost of the enhancements, according to the following principles:*

> *1. Generators share of the cost should be apportioned on the basis of the incremental rated peak output of the generation equipment operated at the site.*
>
> *2. Load customers' share of the cost should be apportioned according to their respective non-coincident incremental peak load requirement as reasonably projected.*
>
> *3. As between load customers and generators, the costs attributable to a given enhancement of connection assets should be apportioned according to whose incremental coincident peak flow triggered the upgrade.*

6.3.1 Analysis and Findings

188 Hydro One generally agreed with this proposition. Regarding the apportionment of costs among load customers on the basis of their respective non-coincident incremental peak load requirement, as reasonably projected, Hydro One proposed that the Board define "reasonably projected" to mean the load forecast agreed upon by the customer and the transmitter. Hydro One was of the view that the apportionment of costs between a load customer and a generator, based on whose incremental coincident peak flow triggered the upgrade, might be difficult to implement. Hydro One was of the view that further assessment is required to determine if this is the most appropriate approach.

189 AMPCO submitted that, where a customer has made a financial contribution toward the cost of Connection facilities, the Code should provide that any subsequent customer connecting to those facilities is required to reimburse the first customer for some part of the financial contribution made by the first customer.

190 ECMI suggested that the requirement for generators to contribute to the costs of new Connection facilities might be a deterrent to new generation.

191 The IMO submitted that the Code should clarify and preserve the responsibility of a sole beneficiary of a new or modified Connection to pay the costs of that Connection. The Code should also include a requirement that the transmitter provide a detailed facilities plan to establish that the system modifications required to incorporate new or modified Connections that were not otherwise planned.

192 RP-1999-0044 established the principle that customers who require the construction of new Connection facilities to meet their needs should bear the cost of those facilities, to the extent that the cost is not recovered in the Connection revenue. The Board is of the view that this principle is an appropriate one to incorporate into the revised Code. However, customers should not be required to bear the cost of facilities that were otherwise planned by the transmitter. In order to ensure that this does not happen, a transmitter will be required to provide to a potential or existing transmission customer, as part of the connection protocol, any pertinent existing transmission plans dealing with system expansion that cover the portion of the transmission system under review. Such plans are expected to be developed by transmitters to address growing demand, system sustainability, system reliability and integrity. Such a transmission plan will be essential to determine whether a particular connection project is truly triggered by the specific needs of a customer.

193 With regard to cost sharing among transmission customers, the Board is of the view that:

* Where more than one transmission customer requires or benefits from enhancements to a particular Connection, all of those customers associated with that Connection facility shall share the cost of the enhancements, based on how much of the Connection facility capacity is required to meet the needs of each customer.

* For generators, this will be measured on the basis of the incremental rated peak output of their generation equipment. There is no reason to consider this to be a deterrent to new generation because this is a direct measure of one of the costs incurred by new generation. Generators should be responsible for the costs associated with Connection facilities they cause.

* For load customers, their share of the cost shall be based on their respective non-coincident incremental peak load requirement as reasonably projected by the load forecast agreed upon by the customer and the transmitter.

* For Connection facilities with a mix of load customers and generators, the costs of an enhancement to Connection assets shall be apportioned according to the incremental coincident peak flow that triggered the upgrade. Because of the power flow pattern of loads versus generators, in most cases the trigger would be attributed to either the load or the generation. If there is more than one load customer or generator causing the trigger, the sharing of Connection costs among them would then follow the criteria established above for either load customers or generators, as the case may be.

194 The Board agrees that it would be appropriate for the revised Code to provide for a customer who made a financial contribution toward Connection facilities to be reimbursed by those customers who are subsequently connected to those Connection facilities. The revised Code shall specify that if an additional customer connects within five years from the in-service date of a new Connection facility which was paid for by the first customer, then the transmitter shall require that the additional customer make a financial contribution that will be used by the transmitter to reimburse the first customer. The methodology to be followed is dealt with later in Chapter 8 of this Decision. This should not occur often because the reinforcement of Connection facilities should generally be at a capacity level sufficient to meet the capacity needs of that first customer, subject to equipment standards and good utility practices. If a transmitter reinforces the Connection facility with a higher capacity level in anticipation of future load growth, the transmitter will not be permitted to charge the first customer for the cost associated with the capacity that exceeds that customer's needs. This would be an unfair burden to impose on a customer if the subsequent load growth did not occur. For instance, such a requirement could inhibit the development of new generation, if a new generator had to pay for more Connection capacity than it required subject to the criterion dealing with specification of standard transmission element capacities and sizes.

195 The Board believes that transmitters may be able to recover costs associated with this overbuild through enhanced revenue requirement, but generally may not charge these specific costs to connecting customers. However, where the transmitter is aware of customers who will require connection to a Connection facility within five years of the expected in-service date for that facility, the transmitter should include the additional Connection capacity. The transmitter shall require a security deposit from each anticipated transmission customer in order to accommodate their capacity needs. The security deposit shall be calculated using the Board approved economic evaluation procedure. Should such a customer refuse to provide a security deposit to the transmitter to cover its share of the Connection reinforcement cost, the transmitter is not obliged to include capacity for their use in the Connection facility until a deposit is provided in full.

196 The revised Code shall specify that any customer who contributes to a reinforcement of Connection facilities shall be entitled to be served at the capacity level (i.e., load forecast for consumers and distributors or forecast flow capacity level, in the case of generators) included in the contractual agreement and used in the economic evaluation specified in the Code.

6.4 COST RESPONSIBILITY- BOARD PROPOSITION NO. 6.4

197 *The Code should contain provisions permitting a transmitter to finance customers' capital contributions. Where a transmitter agrees to finance a capital contribution, the carrying charges should be in accordance with the transmitter's approved cost of capital (i.e., Board approved capital cost structure and associated cost components).*

6.4.1 Analysis and Findings

198 Hydro One was concerned that it did not have the competencies, authority or ability to manage this kind of financial risk. Hydro One was also concerned that this requirement would divert the transmitter's available cash flow away from needed transmission investments and could lead to higher costs for transmission pool customers. Should the Board decide to implement this proposition, Hydro One submitted that the transmitter should be permitted to vary financing charges and the financing periods to reflect the risk of individual projects.

199 GLPL agreed with the proposition, provided it can be interpreted to mean that such financing is voluntary and that a transmitter may chose not to finance a customer's capital contributions.

200 TransAlta supported this proposition, saying that the requirement to make certain financing options available to customers would not be an undue burden on a regulated transmitter with guaranteed revenue recovery, taking into account the asset-intensive nature of transmission systems, and the existence of standard industry practices for financing such assets.

201 CAC and VECC supported the GLPL approach, which would permit a transmitter to finance a customer's capital contributions without requiring them to do so. This would be appropriate because it would allow transmitters to avoid situations where they consider the risk to be too great, given the permitted rate of return. The corollary of this would be that any financing risk, including default, should be borne by the transmitter's shareholders and not its ratepayers. It would also be reasonable for the transmitter to recover in such financing arrangements any administration costs associated with establishing the financing agreement.

202 ECAO opposed the proposition, for two reasons. Firstly, the pool funded option contains a number of subsidies for Hydro One's Connection work and should be eliminated. An example is that the pool funded option subsidizes the cost of credit for customers who choose that option, because the pool is not compensated for the credit risk accompanying the Connection Revenue. By contrast, if a customer finances the costs of connection on its own, a lender would charge for financing costs, including the cost of credit risk. Secondly, the transmitter would not only fund the pool funded portion at its cost of capital, it would also fund the customer's capital contribution at its cost of capital. This mandatory financing proposition would tie up the transmitter's capital which could be used for other purposes, thereby creating an opportunity cost.

203 The IMO asserted that the Board must approach the issue so as to ensure that such financing does not become a source of on-going disputes between transmitters and connection customers. The IMO also submitted that the Board should avoid transferring significant financial risks to transmission ratepayers or diverting scarce resources that might otherwise be used to maintain and operate existing transmission facilities efficiently, potentially putting reliability or safety at risk.

204 In RP-1999-0044, the Board was of the view that Ontario should move towards a competitive transmission connections market. In light of this objective and the numerous concerns raised by the parties, the Board is of the view that this proposition should not be reflected in the revised Code.

6.5 COST RESPONSIBILITY- BOARD PROPOSITION NO. 6.5

205 *The Code should contain provisions for renewable energy projects which oblige the transmitter, if requested, to finance the transmission customers' capital contribution over a period of not less than five years. The carrying charges applied to the outstanding balance in these cases should be at a rate no greater than the transmitter's approved cost of capital.*

6.5.1 Analysis and Findings

206 Hydro One disagreed with this proposition. If the Board believes it is appropriate for utilities to engage in these activities, it should permit transmitters to set interest charges and financing periods that protect transmission pool customers and the transmitter. Hydro One was concerned that a mandatory requirement would result in higher costs that might be borne by transmission pool customers. Government policy appears to limit the transmitter's role to the ownership and operation of transmission facilities. Hydro One was of the view that it is not permitted under statute to implement this proposition. Hydro One stated that it has no authority under its general by-law to loan money unless it is to secure the performance of an obligation. Both Hydro One and GLPL were concerned about the potential effect on their credit ratings. GLPL was also concerned that a mandatory financing obligation would tie up a transmitter's capital which would prevent it being used for transmission investment. The mandatory financing obligation could lead to subsidization of renewable energy projects, which would amount to discrimination against non-renewable energy projects, contrary to section 26 of the *Electricity Act.*

207 GEC was of the view that the proposed five year financing obligation would be of some assistance to renewable energy projects. However, GEC was concerned that in a situation involving renewable generation, such as wind generation, where a new line will be needed but no single wind generation project could justify it, the costs and risk will still preclude renewable generation development, assuming the new line would be considered a Connection facility. Consideration needs to be given to how the cost of Connection facilities can be shared by subsequent developers of renewable generation, particularly where a required transmission line far exceeds the requirements of the triggering party.

208 The EDA noted that this proposition appears to force the transmitter to bear the risk of certain projects, contrary to the principle of avoidance of cross subsidization.

209 CAC and VECC submitted that this proposition is inappropriate as it does not provide any mechanism for the transmitter to address concerns with respect to the risk of the renewable project and the credit worthiness of the proponent.

210 ECAO indicated that there are administration costs associated with borrowing and loaning money, and unless these costs are recoverable by transmitters, transmitters will be required to subsidize renewable energy projects. A mandatory financing obligation would amount to discrimination against non-renewable energy projects that may not be eligible for financing, contrary to section 26 of the *Electricity Act, 1998.*

211 As with the previous proposition, the IMO asserted that the Board must approach the issue so as to ensure that such financing does not become a source of on-going disputes between transmitters and connection customers. The IMO also submitted that the Board should avoid transferring significant financial risks to transmission ratepayers or diverting scarce resources that might otherwise be used to maintain and operate existing transmission facilities efficiently, potentially putting reliability or safety at risk.

212 In light of concerns raised by the parties, the Board is of the view that this proposition should not be reflected in the revised Code.

6.6 COST RESPONSIBILITY- BOARD PROPOSITION NO. 6.6

213 *The Code should contain provisions to indicate that O&M costs are the responsibility of the owner of the assets. A transmitter's O&M costs associated with the connection of a new or upgraded load customer will be recovered through Connection pool rates. A transmitter's O&M costs associated with the connection of a new or upgraded generator will be recovered as a capital contribution, at the time of connection, equal to the present value of attributable O&M costs over the expected life of the connection.*

Clarification of Proposition in Appendix A of Procedural Order No.4 dated July 30, 2003

214 *In the case of allocation of O&M costs, it has been proposed by some stakeholders that incremental O&M costs associated with new Connection assets are the responsibility of the owner of the asset. This proposition suggests that whoever owns the asset should be responsible for its opera-*

tion and maintenance. Second, the proposition provides that if a new or upgraded customer connection (load customer or generator) requires the transmitter to reinforce existing or construct new Connection assets, the transmitter would incur both incremental capital costs and incremental O&M costs. Pursuant to this proposition, these incremental costs associated with connection are allocated to the specific connecting customer. If the customer connection does not require the transmitter to reinforce existing or build any new Connection incremental assets, then no incremental O&M costs of the transmitter ought to be allocated. Third, it is suggested in the case of a load customer, the allocated costs should be incorporated into the economic evaluation (i.e. they are capitalized) to determine the degree of revenue shortfall that the customer is responsible for. In the case of a generator, there would be no offsetting revenue in the economic evaluation and the generator would therefore be responsible for the Transmitter's total incremental cost of Connection capital and O&M.

6.6.1 Analysis and Findings

215 The Board finds that in the case of allocation of O&M costs, the reasonable attributable O&M costs associated with new connection assets are the responsibility of the owner of the asset. If a new or upgraded customer connection for a load customer requires the transmitter to reinforce existing or construct new Connection assets, the transmitter would incur both attributable capital costs and attributable O&M costs. The reasonable fully allocated costs of attributable assets associated with Connection are allocated to the specific connecting customer. If the customer connection does not require the transmitter to reinforce existing or build any new incremental Connection assets, then no O&M costs of the transmitter ought to be allocated, since these costs are already built into rates. In the case of a load customer triggering a Connection facility upgrade, the reasonable attributable O&M allocated costs of the transmitter shall be incorporated into the economic evaluation to determine the capital contribution for which the customer is to be responsible.

216 The parties to the Settlement Conference agreed that there should, at the present time, be no allocation to generators of incremental O&M costs for new or modified connections.

217 The Board accepts the consensus of the participants in the Settlement Conference that, at the present time, there shall be no allocation to generators of incremental O&M costs for new or modified Connections, in view of the relatively small amounts involved. However, the Board will require transmitters to keep track of the estimated annual aggregate costs associated with providing all new generator connections that involve incremental O&M services associated with transmitter-owned new or modified Connections at no cost to the generators.

6.7 COST RESPONSIBILITY- BOARD PROPOSITION NO. 6.7

218 *The Code should contain provisions which establish that capital costs of monitoring and testing equipment for new or enhanced connections should be borne by the owner of the equipment. The costs associated with monitoring and testing activities should be borne by the party which owns the equipment regardless of whether or not the transmitter is the requesting party for such testing. A transmitter's monitoring and testing costs associated with the connection of a load customer will be recovered through Connection pool rates. A transmitter's monitoring and testing costs associated with the connection of a generator are recovered as a capital contribution, at the time of connection, equal to the present value of attributable monitoring and testing costs over the expected life of the connection.*

6.7.1 Analysis and Findings

219 Hydro One proposed that for new generator connections, the capital and O&M costs for monitoring and testing equipment incurred by the transmitter would be recovered from the generator on a cost-recovery basis as incurred.

220 OPG and AMPCO submitted that a reasonableness standard is necessary to ensure that the transmitter does not require more monitoring and testing equipment than necessary. There should be explicit mechanisms in place for an expedited, independent review by the Board of any costs considered excessive.

221 Brighton did not object in principle to the recovery by a transmitter of reasonably-incurred monitoring and testing costs as long as it is clear that there is no potential for double recovery of those costs.

222 ECMI submitted that there should be timely notice of any potential monitoring and testing requirements so there is an opportunity to explore alternative or less costly monitoring and testing options. In all cases, any monitoring and testing requirements which results in costs for a customer should be contestable.

223 In the Board's view, monitoring and testing are important components of ensuring the reliability of the transmission system. Monitoring and testing equipment may be required on the customer side of the connection with the transmitter, for the protection of both the transmission system and the customer. It is appropriate for the transmitter to require such equipment, subject to a standard of reasonableness.

224 The Board notes that monitoring and testing equipment that transmitters own is classified with respect to the asset it services. For example, monitoring and testing equipment at a transformer station that is part of the Network pool is classified as a Network asset. Similarly, such equipment at a transmitter-owned Connection transformer station is classified as part of the Transformation Connection pool. The Board will follow the principle established in section 6.1 of this Decision as applied to the monitoring and testing equipment and associated capital costs. If monitoring and testing equipment is installed in Network stations to accommodate new or enhanced connections for load customers or to connect new generation the associated costs should be borne by all ratepayers.

225 The Code will require that the reasonable capital costs of such monitoring and testing equipment for new or enhanced connections that is owned by the connecting customer be borne by that customer. In addition, the Board is of the view that a transmission customer connecting to the transmission system will be responsible for the reasonable capital costs associated with the monitoring and testing equipment which the transmitter would specify and install at its Connection facilities to accommodate that new connection. If the customer is a load customer, in the process of performing an economic evaluation as outlined in Chapter 8 of this Decision, such a cost will be included with the capital cost of the reinforcement to the Connection facilities incurred by the transmitter to accommodate that customer. If the connecting customer is a generator, the generator will pay this capital cost up front.

226 The reasonable costs associated with performing verification tests by the transmitter on monitoring and testing equipment, associated with the operation of a transmission customer's facilities, shall be borne by that customer regardless of whether or not the transmitter is the requesting party for such testing. If the customer chooses to do so, this obligation may be met on a current basis as and when the testing costs arise, or may be subject to inclusion in the economic evaluation according to agreement with the transmitter.

227 In the revised Code the Board will indicate that requirements for monitoring and testing equipment and associated verification testing specified by the transmitter shall not exceed the requirements of the transmitter with respect to the transmitter's own equipment performing the same function. Transmitters shall recover both their relevant capital costs for its monitoring and testing equipment and costs associated with monitoring and testing activities from customers.

6.8 COST RESPONSIBILITY- BOARD PROPOSITION NO. 6.8

228 *The Code should contain provisions establishing that the reconnection process should be based on the following principles.*

> *1. No reconnection fees related to system studies or any other activities, should be imposed on transmission customers unless the transmitter has obtained Board approval for them [Ref. Principle No. 12 in Chapter 2].*
>
> *2. Where the transmitter intends to perform system studies associated with a reconnection it must demonstrate that conducting the studies is required in order to preserve the integrity of the system, or to comply with requirements imposed by the IMO. Only such studies as are necessary to accomplish these purposes should be performed.*

6.8.1 Analysis and Findings

229 Hydro One agreed with the proposition, but submitted that the appropriate treatment of reconnections depends on the cause and duration of disconnection. In some cases, reconnection may need to be treated as a new connection to ensure that transmission capacity is still available to accommodate the reconnecting customer. Prior to reconnection, the reconnecting party must fulfill all requirements in the Market Rules and the Code. Hydro One also pointed out that the reconnection costs addressed in this proposition have not historically been included in the transmitter's cost of service. Instead, they have been paid for by the reconnecting customer as an up-front charge. If the Board decides that customers no longer have to pay these costs, then allowance should be made for transmitters to recover these costs from all customers in rates.

230 ECMI advocated requiring timely notice to the reconnecting customer of the transmitter's technical and connection process requirements.

231 CAC and VECC agreed with Hydro One that the costs referred to in this proposition have not traditionally been included in a transmitter's cost of service and implementation of the proposition would require an adjustment to the transmitter's revenue requirement. CAC and VECC submitted that it would be inappropriate to adjust the current transmission rates for this one item in isolation.

232 It is the Board's view that a transmitter's fees for system studies or for any activities related to the reconnection of a transmission customer should not be imposed on that transmission customer unless the transmitter has obtained Board approval under section 78 of the Act. Where the transmitter intends to perform system studies associated with a reconnection, it must demonstrate that the studies are required to ensure the integrity of the system, or to comply with requirements imposed by the IMO. Only those studies that are necessary to accomplish these purposes shall be performed.

233 The revised Code will also require that the transmitter notify a transmission customer within a reasonable period of time following a written request by the customer indicating an intention to

reconnect, of the requirements for reconnection, the time line for the reconnection process, and the cost of such an undertaking.

6.9 COST RESPONSIBILITY- BOARD PROPOSITION NO. 6.9

234 *The Code should contain provisions establishing that switching costs and any associated overtime costs should be paid by the requesting party.*

6.9.1 Analysis and Findings

235 Hydro One stated that, historically, transmitters and distributors have not charged each other for conducting switching operations. These operations were done for the benefit of all customers. Hydro One submitted that the historical practice should continue.

236 APPrO, the EDA, Brantford, CAC and VECC were of the view that switching was part of the O&M costs recovered in rates and they submitted that customers should only pay for switching costs incurred on an overtime basis.

237 AMPCO submitted only reasonable costs should be recoverable, to ensure that transmitters properly control their costs.

238 Generally there was consensus that the revised Code should establish that switching operations which take place outside the normal operating hours of the transmitter, and that arise due to a customer request, should be paid for by the requesting party, including any associated reasonable overtime costs. The Board accepts this consensus for the purposes of the Code. The ability to recover such costs is subject to Board approval under section 78 of the Act.

6.10 COST RESPONSIBILITY- BOARD PROPOSITION NO. 6.10

239 *The Code should require that the transmitter undertake a Customer Impact Assessment (CIA) in association with each new or upgraded customer connection to determine impacts on other customers.*

6.10.1 Analysis and Findings

240 Hydro One generally agreed with this proposition. However, Hydro One proposed that a CIA study be conducted only if the new or upgraded customer connection is subject to the IMO's Customer Assessment and Approval (CAA) process. Connections that are not subject to the IMO's process are deemed not to have an impact on the transmission system or other customers. The IMO agreed with Hydro One and further submitted that this is consistent with the IMO Market Manual 2.10 which identifies those connection proposals which require a formal study. APPrO submitted a CIA may not always be necessary and the Code should provide for a waiver of the CIA requirement.

241 VECC submitted that the Code should require transmitters to undertake a CIA study of any new or upgraded customer connection in order to determine the impacts on other customers. It should be made clear that the costs of these studies are to be recovered from the customer requesting the new connection or upgrade. The Code should also make clear that it is the responsibility of the customer requesting the new connection or upgrade to address any impact on other customers.

242 The Board acknowledges the submissions of Hydro One and the IMO. The revised Code will require a transmitter to conduct a CIA study in all cases where the connection is subject to the IMO's CAA process. In cases where the IMO's CAA study is not required but the transmitter determines there is an impact on existing transmission customers, a CIA study shall also be completed. Where a CIA study is not performed, the transmitter will be required to notify all customers in the vicinity of the connection, advising them of the proposed connection work and the fact that it has no negative impact and that no specific CIA study will be done.

243 The Board is of the view that the CIA report must provide for each customer two values of short circuit levels; one value of short circuit level based on system conditions prior to the proposed connection, and the second short circuit level for the system condition assuming the new connection is in service. This is considered crucial as a customer conducts its assessment of the impacts of the increased fault levels, and considers whether it should undertake mitigating measures to ensure continued safe operation.

244 The Board is of the view that transmitters may charge customers, as well as the IMO, for customer connection studies, including the CIA report, on either a cost pass through basis or by way of specific fees. In either case, the charges shall be based on the incremental revenue requirement beyond what is presently included in the transmitter's approved revenue requirement and associated rates. Standard fees for customer connection studies are, as a matter of law, rates pursuant to section 78 of the Act, and may not be charged to anyone without approval of the Board. Upon approval by the Board, the transmitter shall publish information relating to its charges for customer connection studies along with a description of the scope of work covered by the studies.

6.11 COST RESPONSIBILITY- BOARD PROPOSITION NO. 6.11

245 *Existing transmission customers are expected to ensure that their equipment is robust enough to accommodate growth of the transmission system provided that such short circuit levels do not exceed the allowable "Fault Levels" listed in Appendix 2 of the Code. The Code and the Connection Agreement in Appendix 1 should contain provisions requiring that transmission customers be responsible for upgrading their own equipment to the minimum baseline performance requirements established by the CIA study.*

6.11.1 Analysis and Findings

246 Hydro One agreed with this proposition.

247 The IMO submitted that the scope of the CIA should be expanded, requiring the transmitter to establish baseline performance requirements for existing customer owned connection equipment.

248 The Board is of the view that the transmission system is dynamic in nature and that a transmission customer must be expected to upgrade its own equipment, from time to time, to adjust to a changing transmission system. The Board agrees with the IMO that the CIA process should be expanded to establish baseline performance requirements for existing connection equipment owned by customers that will be affected by increased short circuit levels that result from connecting a new customer or upgrading a connection of an existing customer.

249 The Board expects that the CIA studies prepared by transmitters will provide information to all affected customers regarding the fault levels before and after the new customer connection. The Board is of the view that existing transmission customers should be required to upgrade their own equipment, at their own cost, to handle increased short circuit levels which may result from connecting a new customer, provided that these levels do not exceed the allowable fault levels currently set out in Appendix 2 of the Code.

250 The Board, therefore, requires that the revised Code and the associated Connection Agreement shall contain provisions requiring that all existing transmission customers be responsible for upgrading their own equipment to the minimum new baseline performance requirements that are established by the CIA study prepared by the transmitter. In all cases, the transmitter is responsible for ensuring that short circuit levels do not exceed the maximum fault levels set out in Appendix 2 of the Code.

6.12 COST RESPONSIBILITY- BOARD PROPOSITION NO. 6.12 (INITIALLY PRINCIPLE NO. 11)

251 *Transmission Connection assets are defined as stated in Hydro One's evidence in Proceeding RP-1999-0044. The Transformation Connection pool refers to high voltage transformation facilities that step down voltages from transmission levels to distribution levels to supply customers. The Line Connection pool refers to radial transmission lines that are specifically dedicated to serving a single customer or group of customers.*

6.12.1 Analysis and Findings

252 At the Settlement Conference, the participants reached agreement that this classification issue should be addressed in more detail prior to or at the next cost allocation and rate design proceeding.

253 The Board recognizes there are substantial issues arising from the definition of Line Connection assets and Network assets, and there is not any evidence as to the expected number of radial lines that may in the future be subject to reinforcement and become "Local Loops".

254 In light of this, the Board is of the opinion that this classification issue as well as the issues outlined in Appendix B of the Facilitator's Report (which is included as Appendix B of this Decision), should be addressed in a proceeding prior to or at the next cost allocation and rate design proceeding. The resolution of such issues would help streamline the next transmission rate proceeding.

255 In the interim, the Board finds that the "Local Loops" are Network assets. The Board relies on its interpretation of the definition for Line Connection assets which was submitted in the prefiled evidence of RP-1999-0044 and in the response to an Interrogatory by Hydro One/OHNC. Therefore, if a reinforcement of a transmission line results in the reclassification of the transmission line from Line Connection asset to Network asset, any financial implications imposed on or agreed to by parties as a result of such reclassification of the "Local Loops" will require re-evaluation. At that time, any amounts owing, including interest, shall be settled between the parties.

256 The Board notes that there was a recent case involving a leave to construct application by Hydro One for reinforcement of the Ottawa City Centre (RP-2003-0038). The "Conditions of Approval" attached to that Decision anticipated that the issue of classification of "Local Loops" would be addressed in this Phase 1 Decision. As noted above, however, the Board is now of the opinion that the classification issue should be addressed in a proceeding prior to or at the next cost allocation and rate design proceeding. In light of this, the Board will not require Hydro One to revisit the classification of "Local Loops" set out in the Decision of RP-2003-0038 as a result of this Phase 1 Decision, but rather will wait for the outcome of the proceeding discussed above.

257 The above interim finding does not alter the basis for a transmitter to charge for Line Connection Service as outlined in the Transmission Rate Order (Schedules, Item D), issued April 30, 2002 and applicable to all four licensed transmitters in Ontario.

7. CONTESTABILITY

7.1 CONTESTABILITY- BOARD PROPOSITION NO. 7.1

258 *The Code should allow transmission customers the choice of contracting with any qualified contractor for the design and construction of connection facilities, whether or not the connection facility is pool-funded, if the offer meets the following conditions.*

> *1. The project requires a capital contribution from the load customer; and*
>
> *2. The construction work would not involve work with existing Connection facilities.*
>
> *3. The contractor doing the construction is qualified to do the proposed work.*

7.1.1 Analysis and Findings

259 Hydro One disagreed with this proposition due to concerns regarding safety, security and reliability. Very clear criteria governing design, construction, inspection, testing and commissioning would be required. Hydro One also suggested that there would be challenges associated with existing labour agreements. GLPL submitted that if a customer turned over an asset to the transmitter, the transmitter should be able to recover all costs required to bring the asset up to required standards.

260 The EDA was of the view that customers should have the right to complete the detailed design of Connection pool assets in addition to the right to do the actual construction.

261 ECMI proposed that customers be able to choose to do all or part of the required Connection work.

262 ECAO questioned the rationale for allowing competition on pool funded assets only when a capital contribution is required and only on assets that are not existing assets of the transmitter.

263 The Board is of the view that generators should design, construct, pay for and own all new dedicated connection facilities required to connect to the transmitter's transmission system. For required reinforcement on existing dedicated or shared Connection facilities owned by the transmitter, transmitters shall retain the right to make modifications to existing transmitter-owned Connection facilities required to accommodate the generation connection and charge the generator as specified in Chapter 8 of this Decision. This requirement is consistent with the current transmission rate regime under which generators do not pay rates.

264 In the Board's view, new Connection facilities work should be contestable. This approach is consistent with the principle expressed throughout this Decision that the development of the transmission system should be accomplished, wherever practical, through the interplay and competition between qualified suppliers. A transmission load customer requiring new connection facilities to connect to the transmitter's transmission system will have two options; either design, construct, pay for and own the new connection facilities or have the new connection facilities owned by the transmitter. Under the latter option, the transmitter would carry out an economic evaluation to determine what, if any, capital contribution will be required from the customer. The customer may choose to accept the transmitter's cost of constructing the new Connection facilities or contract with any qualified contractor for the construction of part or all of the Connection facilities, other than work to be done on the transmitter's existing Connection facilities. Regardless of which option the customer chooses, a transmitter shall retain the right to work on its own existing facilities, in the interests of operational safety.

265 The Board accepts the submission of ECAO that new Connection facilities work should be contestable regardless of whether a capital contribution is required from the transmission customer. However, the design of any Connection facilities, that will be owned and operated by the transmitter, should be carried out by the transmitter.

266 In section 7.3.1, the Board prescribes the process, responsibility and protocol for contestable work.

7.2 CONTESTABILITY- BOARD PROPOSITION NO. 7.2

267 *The Code should contain provisions which require the transmitter to use the same fully allocated costing methodology for all purposes, and to demonstrate the same.*

7.2.1 Analysis and Findings

268 Hydro One expressed a need for an appropriate degree of flexibility to recognize specific circumstances. When constructing facilities to be owned by a customer, for example, Hydro One submitted that it is appropriate to add a margin to the calculated cost to determine the bidding price. Hydro One interpreted fully allocated costing to mean design and construction overheads for a Connection project plus a reasonable share of indirect overhead support costs. Capitalized overheads associated with other aspects of the utility's operation not affected by the Connection project would not be included. This costing methodology reflects the incremental costing approach as required by the economic evaluation methodology of the current Code.

269 Hydro One also expressed a concern about the effect Economic Evaluation proposition No. 4, which provides for the netting out of the capital contribution requirements for Line and Transformation Connection facilities, might have on contestability.

270 ECAO submitted that assets to be owned by the transmitter should be costed using fully allocated costs. To do otherwise would interfere with the connection market becoming competitive.

271 The issue of what constitutes fully allocated costs was one of the issues addressed in the Settlement Conference. As Hydro One observed, this is an issue relating to both contestability and economic evaluation. Hydro One indicated that for all capital assets it makes an allocation of a portion of the indirect overhead support costs in the economic evaluation calculations before such assets are added to rate base. This treatment applies to Connection assets that are priced on an incremental basis, according to the economic evaluation methodology of the current Code.

272 There were two basic opinions expressed at the Settlement Conference, as reflected in section 2 of the Facilitator's Report. A number of participants suggested that there was a need for a hearing dedicated to this specific issue. The second point of view held that the issue could be addressed in a focused consultative process with the results then incorporated into the next cost allocation and rate design hearing. However, there was agreement by all parties that there should be some form of Board initiated process, prior to or at the next transmission cost allocation and rate design hearing, to determine which costing methodology for the treatment of indirect overhead support costs should be adopted. There was also agreement that pending the outcome of the proceeding, the costing methodology currently utilized should remain in place.

273 The Board accepts the consensus of the parties that the costing methodology currently used by individual transmitters should continue to apply, pending a more detailed review of this issue.

274 The Board is of the view that the principle of the costing of Connection facilities, for the purpose of submission to a connecting load customer or a generator, should be on the same basis as the eventual cost of that facility when it enters the transmitter's rate base. Of particular concern is any tendency for the transmitter to use varying methodologies in establishing the structure of its costs. The determination of the relative weighting and constituent elements of the cost structure should be the subject of more detailed consideration. The process should result in a single consistent model to be used in all circumstances. Such a costing approach must be based on allocating the appropriate direct and indirect overheads to the Connection facilities, and will be determined in a proceeding prior to or at the next cost allocation and rate design proceeding. In the meantime, the costing methodology currently used should continue to apply, pending a more detailed review of the issue.

7.3 CONTESTABILITY- BOARD PROPOSITION NO. 7.3

275 *In the event that a connecting customer chooses to obtain the services of an alternative contractor, the Code should require the transmitter to:*

> *1. Describe work that is contestable on the basis of conditions established in the Code;*
>
> *2. Provide a separate estimate for contestable and non-contestable work that can be audited if necessary to demonstrate no cross subsidy from non-contestable to contestable work;*
>
> *3. Provide a reasonable period of time for the customer to obtain competitive quotes for contestable work;*
>
> *4. Provide to the connecting party cost estimates and technical and engineering specifications and data. The cost estimates should be detailed specifically to the various components of the connection related work, which would allow the connecting party the ability to review and assess the estimated costs for fairness and accuracy; and*
>
> *5. Require the customer who chooses to hire an alternative contractor to construct the facilities to the specifications and standards of the transmitter and to assume full responsibility for the construction of that aspect of the expansion project.*

7.3.1 Analysis and Findings

276 Hydro One agreed that a transmitter should provide cost estimates at a level of detail sufficient to allow the customer to make a decision on whether to carry out contestable connection work. However, the transmitter should not be required to provide more detailed costing or technical specifications without being compensated for it. Hydro One also submitted that what constitutes a reasonable period of time for a customer to obtain competitive quotes should be agreed on by the transmitter and customer.

277 Brighton Power and OPG proposed that transmitters should be required to provide separate detailed estimates of contestable and noncontestable work that can be audited if necessary to ensure that there is no inappropriate cross subsidy between these two aspects of work.

278 AMPCO agreed that it would be equitable for transmitters to be reimbursed for some design expenses if the customer's contractor uses the transmitter's designs.

279 IBEW-CCO submitted that the Board must be particularly vigilant in ensuring fair and effective competition with respect to contestable connection work in Ontario

280 PWU agreed with the proposition but, urged the Board to appreciate the need for flexibility. For example, some projects must proceed on an urgent basis. PWU observed that the transmission system can vary greatly in scope and complexity, and requires high-level expertise and experience.

281 ECAO submitted that information sharing by transmitters remains strikingly deficient. ECAO argued that all relevant information is necessary to determine which contractor should be hired. Therefore, such information should be provided to the customer prior to the time when it must decide which contractor it wishes to hire. The proposed rules should also require transmitters to provide independent contractors, not linked to the transmitter, with all information available to the transmitter including Preliminary Assessment and System Impact Assessment studies done by the IMO or the transmitter, any proposed projects that the transmitter is aware of, and historical constraints and weaknesses in the transmission system.

282 The Board is of the view that a customer should be able to request a transmission connection feasibility study, for which the transmitter may charge the customer in accordance with a Board approved fee schedule. These studies are optional and they can also be performed by either the IMO or an independent consultant.

283 The Board's outline for the roles and responsibilities of a transmitter and the connecting customer during the connection process is prescribed below:

* When a customer requests a connection in writing from a transmitter, the transmitter shall provide once, at no cost to the customer:

  - a description of the work that is contestable and the work that is noncontestable, as provided for in the revised Code;

  - a description of the labour and material required for the contestable work and the estimated capital cost of the connection broken down by engineering, labour, material, equipment, administration and direct and indirect overheads;

  - a description of the labour and material required for the noncontestable work and the estimated capital cost of the connection broken down by engineering, labour, material, equipment, administration and direct and indirect overheads;

- the calculation, including all inputs, done to identify any capital contribution that may be required, using the Board approved economic evaluation methodology.

* If the transmitter is required to develop additional estimates and revised capital contribution calculations because of changes to customer's plans, the transmitter may recover costs for this additional work from the customer.

* The transmitter shall indicate whether the estimates are firm offers or whether they are subject to revision to reflect actual costs. The requirement for separate estimates for contestable and non-contestable work will ensure that they are each costed on the same basis.

* When a customer opts to design, construct, pay for, and own the new connection facilities, transmitters shall provide (at no cost to the customer), information, specifications and standards sufficient to allow the customer to design and construct the new connection facilities that will meet the requirements of the transmitter. The transmitter shall also provide a schedule of Board approved inspection, testing and commissioning fees.

* When a load customer chooses to have the transmitter own the new connection facilities but wants to obtain competitive quotes for the contestable work, the transmitter shall:

    - if requested, provide, at cost, detailed design and technical specifications and standards sufficient to allow the customer to obtain alternate bids for the construction of the new connection facilities to meet the requirements of the transmitter;

    - allow the customer a reasonable period of time to obtain the competitive quotes;

    - provide a schedule of Board approved inspection, testing and commissioning fees;

    - inform the customer of the transfer price which the transmitter will pay the customer when the facility is transferred to the transmitter. This transfer price shall not exceed the transmitter's reasonable cost of doing the work;

    - require the customer who chooses to hire an alternative contractor to construct the facilities to the design specifications and standards of the transmitter and to assume full responsibility for the construction of that aspect of the connection project, its timeliness and its compliance with the transmitter's standards.

* Based on the transfer price (if facilities are transferred), the transmitter shall re- evaluate the economic evaluation to determine whether a shortfall exists and the amount of re-evaluated capital contribution, if any. Where there is a shortfall, the transmitter shall collect that shortfall from the customer.

8. ECONOMIC EVALUATION

8.1 ECONOMIC EVALUATION- BOARD PROPOSITION NO 8. 1

284 *The Code should contain provisions for the methodology transmitters are to use to calculate a capital contribution from customers. For load customers this methodology should be based on a discounted cash flow analysis using attributable costs and forecast revenues for the proposed connection. For generators the capital contribution should equal the total present value of Connection including capital costs and the present value of attributable annual costs.*

8.1.1 Analysis and Findings

285 Hydro One submitted that O&M costs should be recovered from generators on a cost recovery basis, as those costs are incurred. It did not favor the capitalization approach.

286 OPG submitted that when a generator builds, owns and maintains its own connection facility, there should be no capital or operating costs recovered by the transmitter.

287 The EDA submitted that the economic evaluation should include costs and revenues associated with the transmission connection only to the extent that those costs and revenues are associated with accommodating new load.

288 CAC and VECC submitted that the economic evaluation should include all costs, including overhead costs, that will be reflected in the transmitter's capital costs and ultimately in the transmitter's revenue requirement.

289 The Board is of the view that the revised Code should establish the methodology that transmitters are to use in economic evaluations to calculate capital contributions from transmission customers for connection facilities. This will ensure a consistent approach by all transmitters.

290 The Board emphasizes that the underlying rationale for incorporating an economic evaluation into the customer connection process is the need to protect transmitters and their existing ratepayers from potentially subsidizing specific connecting customers. Due to the varying scope and complexity of the transmission system at various locations and the wide variation of customer connection requirements, there is generally little certainty that transmitters will fully recover their connection related costs entirely through rates. The proposed economic evaluation provides the mechanism for calculating any recovery shortfall and ensuring that all connection related costs are recovered either through rates or by way of a capital contribution from the connecting customer:

* For load customers, the methodology shall be based on a discounted cash flow calculation using fully allocated costs of attributable Connection assets and forecast Connection revenues associated with the supply of new load for the proposed connection. As indicated in section 7.2.1, the appropriate methodology for determining fully allocated costs will be the subject of a separate Board initiated review. See also section 8.5.1.

* For generators, the capital contribution shall equal the capital cost of attributable Connection assets paid for by the transmitter. As the Board has already determined above, costs associated with monitoring and testing will be recovered from generators as they are incurred or through some other mutually agreed method.

291 The Board requires transmitters to retain copies of economic evaluation calculations and all associated assumptions and inputs for as long as the customer is connected to the transmitter's system.

8.2 ECONOMIC EVALUATION- BOARD PROPOSITION NO 8. 2

292 *The Code should contain prescriptive rules for all inputs and assumptions (e.g., discount rate) to the economic evaluation.*

8.2.1 Analysis and Findings

293 GEC argued that renewable energy projects are, and should be considered to be, low risk projects in the economic evaluation.

294 AMPCO expressed concerns about the rules defining a shorter revenue horizon for some customers classified as higher risk. Any such classification should be supportable on the basis of tangible evidence.

295 The Board is of the view that prescriptive rules for the inputs and assumptions to be used in an economic evaluation will provide the necessary clarity and predictability for both customers seeking to connect to the transmission system and transmitters:

* The revenue horizon for economic evaluation will be based on risk factors as follows:

- High risk, 5 years
- Medium high risk, 10 years
- Medium low risk, 15 years
- Low risk, 25 years

* The appropriate risk factor to be applied to a project will be based on the recommendations in the *Risk Assessment Methodology Options* report by PHB Hagler Bailly, March 30, 2000 as set out in the existing Code. The Board is of the view that special classes of projects, such as renewable energy projects, should not be singled out for special treatment in this regard, as was proposed by GEC. The Board also notes that the application of risk factors applies only to establishing the appropriate revenue horizon over which revenues will be considered in the economic evaluation. Since generators do not pay rates and, therefore, have no associated revenue, risk factor and revenue horizon are irrelevant to generation connections.

- The discount rate to be used in the economic evaluation is determined on the basis of prospective capital mix (i.e., debt-to-equity ratio), the then current debt and preference share cost rates, and the latest approved rate of return on common equity of the transmitter.

- Discounting must reflect the true timing of expenditures. Up-front capital expenditures will be discounted at the beginning of the project year. Future capital expenditures, throughout the study period, will be mid-year discounted as will annual revenue and O&M expenditures.

- Attributable corporate, municipal and income tax amounts, adjusted by any applicable capital cost allowance (tax shield) will also be included in the calculation.

8.3 ECONOMIC EVALUATION- BOARD PROPOSITION NO 8. 3

296 *The methodology should exclude all Network revenues and all Network costs from the economic evaluation of the new or enhanced load customer connections. In determining connection costs for generators, Network costs should be excluded. There may be exceptional situations where it might be appropriate for a party to seek approval from the Board for a different allocation of Network costs.*

8.3.1 Analysis and Findings

297 There was general support for this proposition. There was also broad agreement that the circumstances under which Network costs might be included in an economic evaluation needed to be clearly established. The IMO submitted that principles should be developed to discourage unnecessary and uneconomic Network expansion. ECMI was concerned that the inclusion of Network costs in an economic evaluation could be a deterrent to new generation.

298 The Board accepts the consensus of the parties on this issue. Network costs will normally be excluded from any economic evaluation of the proposed connection. There may be exceptional situations, where major Network system work having limited value to the Network system may be required as result of the particular proposed connection. It would not be appropriate for ratepayers to bear such costs, since they receive no benefit. For such situations, it will be open to a party to seek approval from the Board to include some or all of these Network costs in the economic evaluation. The process for doing this will be set out in the revised Code. In the event that the Board determines that costs of Network expansion are to be allocated to the connecting customer, then the economic evaluation will include both Network costs and Network revenues.

8.4 ECONOMIC EVALUATION- BOARD PROPOSITION NO 8. 4

299 *The Code should contain provisions that would require that transmitters carry out separate economic evaluations for each of the Transformation and Line Connection pools, but the two evaluations should be netted against each other for the purpose of calculating any capital contribution.*

8.4.1 Analysis and Findings

300 Hydro One opposed the proposition because it would result in cross subsidization between the Transformation and Line Connection pools and would be contrary to the Board's objective of encouraging competition and the use of fully allocated costing.

301 The EDA was of the view that incremental costs and revenues associated with both Line Connection and with Transformation should be included in the economic evaluation.

302 Toronto Hydro submitted that Line and Transformation Connection costs and revenues should be combined for the purposes of economic evaluation.

303 CAC and VECC questioned how the costs and capital contributions should be treated for rate making purposes if Transformation and Line Connection costs and revenues are netted together in the economic evaluation.

304 The Board is of the view that transmitters should carry out separate economic evaluations for Transformation pool assets and Line Connection pool assets.

305 If, for the purpose of calculating the amount of capital contribution required from the customer, these separate evaluations are netted against each other, the result could be cross-subsidization between the Transformation and Line Connection pools. The Board concludes that this is a complex matter that requires further examination. As a result, this issue of netting the two financial evaluations and the associated accounting and rate-making concerns will be addressed at a proceeding prior to or at the next cost allocation and rate design proceeding.

306 The Board finds that pending the outcome of the above mentioned proceeding, the amount of capital contribution will be determined on the basis of individual and independent economic evaluations.

8.5 ECONOMIC EVALUATION- BOARD PROPOSITION NO 8. 5

307 *Capital costs for attributable new Connection facilities should be based on minimum design standards of the transmitter to meet customer needs. Where the transmitter chooses to construct to a higher capacity than what is required by the customer, the incremental costs to do so should not be included in the economic evaluation. Similarly, for enhancement of existing Connection facilities, attributable capital costs to be included in the economic evaluation should be limited to (a) the costs associated with advancing the enhancement work and (b) the costs associated with upgrading to the next highest standard rating to meet the needs of the customer. Capital costs used in these economic evaluations should be fully allocated costs (i.e., include all associated overheads).*

8.5.1 Analysis and Findings

308 Hydro One interpreted fully allocated costs as direct project design and construction overheads plus a reasonable share of indirect support costs, not fully allocated capitalized overheads.

309 ECAO supported the proposition that transmitters should use fully allocated costing. ECAO also submitted that transmitters should be required to file fully allocated costing studies prior to the next phase of the proceeding. Otherwise, there would be no way to evaluate whether costs are properly allocated.

310 CAC and VECC submitted that the evaluation should include all costs, including overhead costs, that will be reflected in the transmitter's capital costs and ultimately, its revenue requirement.

311 The Board is of the view that capital costs used in economic evaluations of pool funded projects and for the provision of third party quotations for construction work will be based on fully allocated costs as determined by a Board approved costing methodology. This methodology will be determined through a proceeding prior to or at the next cost allocation and rate design proceeding. Pending the outcome of the proceeding, the status quo costing methodology will remain in place.

312 The Board is of the view that the capital costs for attributable new Connection facilities should be based on the transmitter's minimum design standards to be applied to meet customer needs. For enhancement of existing Connection facilities, the relevant capital costs shall be limited to the costs associated with advancing the enhancement work and upgrading to the next highest standard rating to meet the needs of the customer. If the transmitter chooses to construct to a higher capacity than what is required by the customer, over and above the next highest standard rating necessary to meet the customer's needs, the incremental costs to do so shall not be included in the economic evaluation. These measures are to ensure that any capital contribution required from a customer will be limited to that amount necessary to meet the customer's needs.

313 The Board confirms the approach that where Connection facilities that have been funded by a customer through a capital contribution are used to supply additional new customers within 5 years of the in-service date of the Connection facilities, the new customers must pay their share of those facilities and the initial contributing customer will receive a rebate. The transmitter shall determine the amount of capital contribution to be paid by the new customer(s) and the rebate to the initial customer based on the following:

* a re-evaluation of the capital contribution requirements using the load forecasts of all customers; and

* an appropriate sharing of the revised capital contribution amount among the initial and the new customers.

8.6 ECONOMIC EVALUATION- BOARD PROPOSITION NO 8. 6

314 *The Code should contain provisions establishing the methodology to be used for the determination of attributable O&M costs. That methodology should require the transmitter to develop and apply average O&M costs incurred for each category of system element, such as towers, conductor, cable, breakers, transformers, etc., and to then apply these averages on a specific per-unit basis to the economic evaluation of a given project.*

8.6.1 Analysis and Findings

315 Hydro One disagreed with the requirement to determine average O&M costs for various system elements. Hydro One submitted that its present methodology based on average cost per transmission facility is simpler to apply and would yield very similar results. GLPL also disagreed with this proposition.

316 APPrO submitted that this proposition would result in different treatment for new and existing generators. Past practice has only required connecting generators to pay the capital costs for Connection facilities used to connect a generator, and not the associated O&M costs.

317 CAC and VECC pointed out that the use of average O&M costs may not be representative of actual O&M costs.

318 This issue was addressed in the Settlement Conference. It was generally agreed by all parties that incremental O&M costs from new or upgraded connections should be determined on an average basis, recognizing that different transmitters will have different average O&M costs reflecting the circumstances of the transmitter concerned. It was also agreed that, at the present time, there should be no allocation of those O&M costs to generators.

319 The Board accepts the consensus reached by the parties.

8.7 ECONOMIC EVALUATION- BOARD PROPOSITION NO 8. 7

320 *The Code should require attributable incremental revenue to be calculated using incremental load with no adjustment for Available Capacity. However, the incremental revenue should be adjusted for the amount by which an existing Connection facility is overloaded to allow the amount of revenue associated with the overload to be credited to the new or enhanced connection.*

8.7.1 Analysis and Findings

321 The EDA and Toronto Hydro proposed that a credit should be applied against the project in recognition of the revenue generated by overloading a Connection facility, from the date that the 10-day Limited Time Rating (LTR) for that facility was first exceeded.

322 ECMI submitted that a more equitable measure of overload would be the amount by which the revenue from the loaded facility is above the average utilization for that class of assets.

323 To address the issue of overload, the Board is of the view that attributable revenue to be included in economic evaluations for new or enhanced Connection facilities shall be based on the greater of:

* the amount by which the customer's proposed load exceeds the customer's existing load; or

* the amount by which the customer's proposed load exceeds the maximum normal planned supply capacity of the existing Connection facilities used by the transmitter to supply the customer.

324 As noted in section 4.2.1 of this Decision, there will be no obligation on a customer to utilize a transmitter's existing available transformation capacity to supply new forecasted load. As indicated in section 4.8.1, customers may also supply existing load without penalty to the degree that this load exceeds the maximum normal planned supply capacity of the transmitter's Connection facility.

8.8 ECONOMIC EVALUATION- BOARD PROPOSITION NO 8. 8

325 *The Code should provide that in conducting an economic evaluation the transmitter should not include sunk costs or historic revenues. Each project should be evaluated on the basis of attributable projected costs and revenues.*

8.8.1 Analysis and Findings

326 There was general agreement among the parties with this proposition, however, ECMI submitted that in determining revenue credits in the economic evaluation, consideration should be given to existing load above established base load, i.e., the average system loading level at the time of market opening for various types of components such as transformer station.

327 The Board is of the view that the economic evaluation process is a current and forward looking exercise and, therefore, for the purposes of the revised Code, economic evaluations will not include sunk costs or historic revenues. The economic evaluation for each new or upgraded connection project shall be based on projected costs and revenues for the supply of new load.

8.9 ECONOMIC EVALUATION- BOARD PROPOSITION NO 8. 9

328 *The Code should prohibit minimum payment obligations. Instead, it should contain provisions which permit the limited periodic reassessment or truing up of the initial load forecast with actual load (subject to exceptions for embedded generation less than 1 MW, measures for energy conservation, energy efficiency, load management and the use of cleaner energy sources as discussed elsewhere in this paper). The proposed true-up process would be a two way true-up where the transmitter would a) credit the customer for any over payment in capital contribution if the customer's load exceeds forecast or b) request additional capital contribution if the customer's load was less than forecast.*

8.9.1 Analysis and Findings

329 Hydro One proposed that transmitters be allowed to choose to forego future true-ups beyond the first true-up period, if they have received adequate protection of their investment.

330 AMPCO proposed that if a customer had been classified as high risk and therefore a short revenue horizon was used to calculate the capital contribution to be paid by the customer, and that customer was still connected and paying transmission charges at the end of that revenue horizon, there should be provision for any excess capital contribution, resulting from the use of a short revenue horizon, to be returned to the customer.

331 True-up methodology was discussed at the Settlement Conference. There were two basic proposals, each of which proposed periodic two-way true-ups. The main difference was with respect to the timing of the rebate by the transmitter if the true-up is in favour of the customer. Under the first proposal, any rebate by the transmitter would be credited, with interest, to a notional account. Any credit balance in that account would not be paid to the customer until the end of the last true-up period. Under the second proposal, any rebate calculated in a true-up period would be paid right away.

332 The Board is of the view that the first proposal provides an appropriate level of security for the transmitter, without causing undue hardship for the customer.

333 The Board's outline for a true-up approach is specified below:

* Transmitters shall carry out periodic reassessment or truing up of the initial load forecast with actual load as follows:

  - for high risk customers, a true-up calculation will be done at the end of each year for five years;

  - for medium risk customers, a true-up calculation will be done at the end of the third, fifth and tenth years;

- for low risk customers, a true-up calculation will be done at the end of the fifth and tenth years. If the calculation that is done at the end of the tenth year shows that actual load has increased or decreased by more than 20 percent of the original forecast load, an additional true-up calculation will be carried out at the end of the fifteenth year.

* If a true-up calculation shows that a customer's actual load is below the forecast load and therefore has not generated the forecast revenue for the transmitter, the customer will make a payment, including interest, to make up the shortfall in revenue. If a customer's actual load is higher than the forecast load and therefore has generated more revenue than forecast, the amount of excess revenue will be posted as a credit to the customer in a notional account. The balance that exists in this account when the last true-up calculation is carried out will be paid out to the customer.

* The true-up calculation will be done using the Board approved economic evaluation methodology, on the basis of the actual load prior to the true-up point and a revised load forecast for the remainder of the revenue horizon used for the original economic evaluation. The load forecast will be adjusted downwards in order to provide relief to customers who installed Embedded Generation of 1 MW or less per unit (2 MW or less per unit for renewables), after the initial economic evaluation was carried out. The load forecast will also be adjusted downwards to reflect the effect of energy conservation, energy efficiency, load management or renewable energy activities that were carried out after the initial economic evaluation.

* The total rebate paid to a customer shall not exceed the customer's original capital contribution.

* For customer connections for which there was no initial capital contribution requirement by the customer, true-ups will be based on a lower load forecast determined by lowering the initial load forecast to the point that the present value of revenue equals the present value of costs. Note that, as stated above, the rebate paid to a customer shall not exceed the original capital contribution and, therefore, in this case, there would be no true-up payments from the transmitter to the customer.

* For customer connections where the load forecast is constrained to a lower value due to the reallocation of Available Capacity by the transmitter, the true-up will be based on the lower constrained forecast.

* For distributors, the load forecast used for true-ups will be further adjusted downwards for any Embedded Generation exceeding 1 MW per unit installed during the true-up period. This additional allowance is granted to distributors since distributors do not have control over the actions of their

specific customers that may choose to install generation on the distribution system.

334 As a result of these requirements to carry out periodic true-up reassessments, the Board is of the view that any additional minimum payment obligations for existing load or future load growth shall not be permitted.

9. CONTRACTUAL ISSUES

9.1 CONTRACTUAL ISSUES- BOARD PROPOSITION NO. 9. 1

335 *The Code should specify that the transmitter should continue with all construction work according to the agreed to project schedule, and is not allowed to stop or delay such work pending the outcome of any dispute resolution process.*

9.1.1 Analysis and Findings

336 Hydro One opposed this proposition for two reasons. Firstly, assuming that the connection work is performed by the transmitter on a time and materials basis, this proposition would require the transmitter to continue the work when there is a risk that the customer might decide to withdraw its connection request based on the outcome of the dispute resolution process. This would put ratepayers at risk. Secondly, this proposition reduces the incentive for customers to resolve disputes with a transmitter. Hydro One proposed an alternative approach that would require the customer to fund all construction costs with periodic payments during construction and have these costs refunded (apart from the capital contribution) to the customer after the facilities are in service and the dispute has been resolved.

337 GLPL, APPrO and AMPCO agree with the proposition.

338 The IMO recognized that both a connection proponent and a transmitter possess contractual rights. The IMO submitted that the Code should contain a requirement that any disputes that may impact construction schedules be resolved in a defined and timely manner so that in-service dates are not placed in jeopardy.

339 The Board is of the view that the transmitter should continue with all construction work according to the project schedule set out in the Connection and Cost Recovery Agreement (CCRA) between the transmitter and the customer. The transmitter shall not stop or delay the work pending the outcome of any dispute resolution process. To reduce the risk to the transmitter and its ratepayers, it is appropriate that the transmitter be permitted to require a security deposit, in a reasonable amount, where applicable, from the connecting customer to cover the construction costs for both Connection and Network assets which are necessary to connect the customer's plant and facilities to the transmission system.

340 The Board is of the view that the transmitter should return security deposits plus accumulated interest promptly to the customer upon completion of the customer's own plant and facilities.

341 The Board recognizes, however, that because of the different cost responsibility, risk and contractual arrangements associated with Network versus Connection related work, the security deposit requirements may be somewhat different. For example, under an alternative bid option, there may be a need for the transmitter to retain a portion of the security deposit, associated with Connection assets, beyond the customer in-service date as a performance bond. The Board also notes that, even though the customer does not normally have cost responsibility for the Network component of

costs, the customer must assume responsibility for any transmitter costs for constructed assets that become unnecessary or stranded as a result of a customer decision to vary its plans. In the event of the Board determining that some or all of the transmitter's investment is stranded, that portion of the security deposit shall not be returned to the customer.

9.2 CONTRACTUAL ISSUES- BOARD PROPOSITION NO. 9. 2

342 *The Code should contain a mechanism that includes a time-limited process for the resolution of disputes regarding compliance with the Code that arise during contract negotiations.*

9.2.1 Analysis and Findings

343 Hydro One agreed with this proposition.

344 APPrO submitted that this proposition is a key requirement for redressing the imbalance of negotiating power arising from the transmitter's monopoly position. APPrO suggests that the Board may also want to consider a dispute resolution process that provides for "off-line" dispute resolution (also with time limits), as opposed to simply a "time limited" dispute resolution. The applicant should have the choice of process.

345 OPG supported this proposition in theory, but stated that there is insufficient detail associated with the process to complete a full review or determine whether the needs of new generators will be met. The critical issue will be the timing and clarity of the dispute resolution process.

346 AMPCO and the IMO also supported this proposition.

347 The Board accepts the general consensus that the revised Code should contain a mechanism that includes a time-limited process for the resolution of disputes between customers and transmitters. The details of the process will be set out in the draft Code in the second phase of this proceeding.

9.3 CONTRACTUAL ISSUES- BOARD PROPOSITION NO. 9. 3

348 *The Code should contain a principle that any existing contracts which have provisions that are inconsistent with the Code are unenforceable, to the extent of the inconsistency.*

9.3.1 Analysis and Findings

349 Hydro One submitted that this proposition should generally apply only prospectively and should not negate clauses in existing contracts that have already been agreed to by the negotiating parties. Some customer contracts with Hydro One already contain clauses that will automatically adjust the terms to ensure consistency with Code amendments. Otherwise, existing contracts should be left as they are. Hydro One agreed that the terms of all future contracts must be consistent with the requirements of the Code.

350 GLPL agreed with the proposition.

351 APPrO supported the proposition and objected to the suggestion by Hydro One that contract terms entered into by transmission customers under duress should be enforceable. Brighton submitted that the unenforceability of existing contractual provisions should be clearly stated as being without prejudice to any claims that a connecting party may make in respect of actions previously taken under the newly-unenforceable provisions. The Board should require parties to an existing contract to realign their commercial arrangements, including the refund of costs already paid, in a manner consistent with the amended Code.

352 Coral agreed with the proposition, provided that only the offending provisions of an existing agreement, rather than the entire agreement, would be unenforceable. This was also supported by CAC and VECC.

353 OPG submitted that the Board should identify a means by which either party to a contract can seek review of specific provisions to determine whether they are unenforceable, in accordance with this proposition. This was supported by CAC and VECC. OPG also submitted that the Board should, at a later stage in the proceeding, identify the provisions in existing contracts that it considers inconsistent with the Code.

354 AMPCO submitted that the proposition should be adopted and should apply to all existing contracts to correct the imbalance in negotiating power between Hydro One and its transmission customers.

355 Brampton supported the proposition, stressing that needed construction work should proceed on schedule despite contractual disputes.

356 The Board is of the view that any provisions in a contract that are inconsistent with the revised Code are unenforceable by the transmitter, to the extent of the inconsistency. The Board does not accept Hydro One's position that this requirement should only apply prospectively, that is, not to existing agreements. When the Board has determined what the appropriate regulatory regime ought to be for the purposes of the Code, the transmitter should comply with that regulatory regime even when it has an existing agreement with a customer. This is necessary to ensure that a double standard is not created based on an arbitrary distinction between customers who have existing agreements with the transmitter and future customers. Identical customers shall not be treated differently by the transmitter based on the date of the agreement they have with the transmitter. The regulatory environment should be consistent for all transmitters and customers.

357 The Board further notes that a transmitter is required to comply with the Code as a condition of its licence and it is always open to a customer to make a complaint to the Board where the transmitter is not in compliance. Either party to a contract or agreement can seek review of specific provisions of an agreement to determine whether or not they are unenforceable and ensure that all commercial arrangements between the transmitter and customer are realigned with the amended Code.

358 The Board considers that the development of interpretive bulletins would be a valuable tool for the parties on-going use of the Code and, accordingly, the Board will develop a mechanism for the creation and dissemination of interpretive bulletins.

359 The Board is also prepared to address those situations where customers signed agreements with the transmitter, while objecting to terms that are inconsistent with the Code.

9.4 CONTRACTUAL ISSUES- BOARD PROPOSITION NO. 9. 4

360 *The Code should contain provisions to balance the need for confidentiality of information about a specific customer with the need to provide information about the transmission system for all customers that may be seeking new or upgraded connections. Competition for Available Capacity is one such example.*

9.4.1 Analysis and Findings

361 Hydro One and GLPL agreed with this proposition.

362 AMPCO also supported the proposition. However, AMPCO submitted that it is not clear how to balance the need for confidentiality with the need to provide information. This requires better definition. If an industrial customer has informed the transmitter on a confidential basis that a plant expansion is planned that will use the Available Capacity, what is the transmitter's obligation to inform other customers on the Connection and how is that balanced with the confidential nature of the information provided?

363 ECMI stated that it is unclear what is meant by "Competition for Available Capacity is one such example".

364 The Board is of the view that the revised Code shall contain provisions that balance the need for confidentiality of information about a customer and the need to provide information about the transmission system to all customers that may be seeking new or upgraded connections. Those provisions will be set out in the draft Code to be developed in the next phase of this proceeding and parties will have an opportunity to make further submissions.

DATED at Toronto June 8, 2004

Signed on behalf of the panel

Paul Sommerville
Presiding Member

qp/e/qlspi

TAB 7

H

2010 CarswellOnt 2353, 2010 ONCA 284, 99 O.R. (3d) 481, 317 D.L.R. (4th) 247, 68 B.L.R. (4th) 159, 261 O.A.C. 306

Toronto Hydro-Electric System Ltd. v. Ontario (Energy Board)

Toronto Hydro-Electric System Limited (Appellant / Respondent in Appeal) and Ontario Energy Board (Respondent / Appellant in Appeal)

Ontario Court of Appeal

K. Feldman, S.E. Lang, J. MacFarland JJ.A.

Heard: October 9, 2009
Judgment: April 20, 2010
Docket: CA C49980

Proceedings: reversing *Toronto Hydro-Electric System Ltd. v. Ontario (Energy Board)* (2008), 93 O.R. (3d) 380, 2008 CarswellOnt 5372, 298 D.L.R. (4th) 231, 53 B.L.R. (4th) 48 (Ont. Div. Ct.)

Counsel: Glenn Zacher, Patrick G. Duffy for Appellant, Ontario Energy Board

James D.G. Douglas, Morgana Kellythorne for Respondent, Toronto Hydro-Electric System Limited

Subject: Public; Corporate and Commercial; Civil Practice and Procedure

Public law --- Public utilities — Operation of utility — Rates — Approval

T Ltd. was electricity distributor — Board made decision under s. 78 of Ontario Energy Board Act, 1998 requiring that dividend paid to city be approved by majority of T Ltd.'s independent directors — T Ltd.'s appeal from part of decision regarding jurisdiction was allowed — Determination set aside to extent that it required dividend be approved by independent directors of board — Trial judge found OEB protects interests of ratepayers, but in ways authorized by statute — Trial judge found no express power to dictate how dividends are declared by directors — Trial judge found core function of OEB is rate-setting, and imposing restrictions on dividends by directors was not necessary or essential to core function — Board appealed — Appeal allowed — True question of jurisdiction did not emerge — Legislative intent was that board could set electricity rates in subjective and open ended manner — Board was entitled to consider history of dividend payments — Board's reasons provided intelligible explanation for determination — Considerations for public monopolies are different from private entities — Board's concerns regarding payout when infrastructure needs were pending, and inter-affiliate relations were reasonable — Board's determination was within range of acceptable outcomes — Authority to approve dividends did not take power away from directors contrary to Business Corporations Act.

Public law --- Public utilities — Regulatory boards — Practice and procedure — Statutory appeals — Grounds for appeal — Lack of jurisdiction

T Ltd. was electricity distributor — Board made decision under s. 78 of Ontario Energy Board Act, 1998 requiring that dividend paid to city be approved by majority of T Ltd.'s independent directors — T Ltd.'s appeal from part of decision regarding jurisdiction was allowed — Determination set aside to extent that it required dividend be approved by independent directors of T board — Trial judge found OEB protects interests of ratepayers, but in ways authorized by statute — Trial judge found no express power to dictate how dividends are declared by directors — Trial judge found core function of OEB is rate-setting, and imposing restrictions on dividends by directors was not necessary or essential to core function — Board appealed — Appeal allowed — True question of jurisdiction did not emerge — Legislative intent was that board could set electricity rates in subjective and open ended manner — Board was entitled to consider history of dividend payments — Board's reasons provided intelligible explanation for determination — Considerations for public monopolies are different from private entities — Board's concerns regarding payout when infrastructure needs were pending, and inter-affiliate relations were reasonable — Board's determination was within range of acceptable outcomes — Authority to approve dividends did not take power away from directors contrary to Business Corporations Act.

Administrative law --- Standard of review — Reasonableness — Reasonableness simpliciter

T Ltd. was electricity distributor — Board made decision under s. 78 of Ontario Energy Board Act, 1998 requiring that dividend paid to city be approved by majority of T Ltd.'s independent directors — T Ltd.'s appeal from part of decision regarding jurisdiction was allowed — Determination set aside to extent that it required dividend be approved by independent directors of T board — Trial judge found OEB protects interests of ratepayers, but in ways authorized by statute — Trial judge found no express power to dictate how dividends are declared by directors — Trial judge found core function of OEB is rate-setting, and imposing restrictions on dividends by directors was not necessary or essential to core function — Board appealed — Appeal allowed — Standard of review was reasonableness — Issue was one of mixed fact and law with policy considerations — Although corporate law principles were involved, regulator had duty to use expertise to apply principles within standard of its objectives — Board did not exceed authority.

Cases considered by *J. MacFarland J.A.*:

Advocacy Centre for Tenants-Ontario v. Ontario Energy Board (2008), 293 D.L.R. (4th) 684, 2008 CarswellOnt 2830, 238 O.A.C. 343 (Ont. Div. Ct.) — considered

ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board) (2006), 263 D.L.R. (4th) 193, 344 N.R. 293, 39 Admin. L.R. (4th) 159, 380 A.R. 1, 363 W.A.C. 1, 2006 CarswellAlta 139, 2006 CarswellAlta 140, 2006 SCC 4, 54 Alta. L.R. (4th) 1, [2006] 5 W.W.R. 1, [2006] 1 S.C.R. 140 (S.C.C.) — considered

C.U.P.E., Local 963 v. New Brunswick Liquor Corp. (1979), 25 N.B.R. (2d) 237, [1979] 2 S.C.R. 227, 51 A.P.R. 237, 26 N.R. 341, 79 C.L.L.C. 14,209, 97 D.L.R. (3d) 417, N.B.L.L.C. 24259, 1979 CarswellNB 17, 1979 CarswellNB 17F (S.C.C.) — considered

Enbridge Gas Distribution Inc. v. Ontario (Energy Board) (2005), 2005 CarswellOnt 39, 193 O.A.C. 180, 74 O.R. (3d) 147 (Ont. C.A.) — considered

Khosa v. Canada (Minister of Citizenship & Immigration) (2009), 82 Admin. L.R. (4th) 1, 2009 SCC 12, 2009 CarswellNat 434, 2009 CarswellNat 435, 304 D.L.R. (4th) 1, 77 Imm. L.R. (3d) 1, 385 N.R. 206, [2009] 1

S.C.R. 339 (S.C.C.) — considered

Natural Resource Gas Ltd. v. Ontario (Energy Board) (2006), 2006 CarswellOnt 4458, 214 O.A.C. 236 (Ont. C.A.) — referred to

New Brunswick (Board of Management) v. Dunsmuir (2008), 372 N.R. 1, 69 Admin. L.R. (4th) 1, 69 Imm. L.R. (3d) 1, (sub nom. *Dunsmuir v. New Brunswick*) [2008] 1 S.C.R. 190, 844 A.P.R. 1, (sub nom. *Dunsmuir v. New Brunswick*) 2008 C.L.L.C. 220-020, D.T.E. 2008T-223, 329 N.B.R. (2d) 1, (sub nom. *Dunsmuir v. New Brunswick*) 170 L.A.C. (4th) 1, (sub nom. *Dunsmuir v. New Brunswick*) 291 D.L.R. (4th) 577, 2008 CarswellNB 124, 2008 CarswellNB 125, 2008 SCC 9, 64 C.C.E.L. (3d) 1, (sub nom. *Dunsmuir v. New Brunswick*) 95 L.C.R. 65 (S.C.C.) — considered

Pasiechnyk v. Saskatchewan (Workers' Compensation Board) (1997), 37 C.C.L.T. (2d) 1, (sub nom. *Pasiechnyk v. Procrane Inc.*) 216 N.R. 1, 149 D.L.R. (4th) 577, (sub nom. *Pasiechnyk v. Procrane Inc.*) 158 Sask. R. 81, (sub nom. *Pasiechnyk v. Procrane Inc.*) 153 W.A.C. 81, [1997] 2 S.C.R. 890, 30 C.C.E.L. (2d) 149, [1997] 8 W.W.R. 517, 50 Admin. L.R. (2d) 1, 1997 CarswellSask 401, 1997 CarswellSask 402 (S.C.C.) — considered

Ryan v. Law Society (New Brunswick) (2003), 2003 SCC 20, 2003 CarswellNB 145, 2003 CarswellNB 146, 223 D.L.R. (4th) 577, 48 Admin. L.R. (3d) 33, 302 N.R. 1, 257 N.B.R. (2d) 207, 674 A.P.R. 207, (sub nom. *Law Society of New Brunswick v. Ryan*) [2003] 1 S.C.R. 247, 31 C.P.C. (5th) 1 (S.C.C.) — considered

Syndicat national des employés de la commission scolaire régionale de l'Outaouais v. U.E.S., local 298 (1988), 95 N.R. 161, 89 C.L.L.C. 14,045, 24 Q.A.C. 244, (sub nom. *Union des employés de service, local 298 v. Bibeault*) [1988] 2 S.C.R. 1048, 1988 CarswellQue 125, 1988 CarswellQue 148, 35 Admin. L.R. 153 (S.C.C.) — considered

Toronto Hydro-Electric System Ltd. v. Ontario (Energy Board) (**2009), 2009 CarswellOnt 2889, 252 O.A.C. 188** (Ont. Div. Ct.) — considered

VIA Rail Canada Inc. v. Canadian Transportation Agency (2007), 2007 SCC 15, 2007 CarswellNat 608, 2007 CarswellNat 609, 360 N.R. 1, 279 D.L.R. (4th) 1, (sub nom. *Council of Canadians with Disabilities v. Via Rail Canada Inc.*) 59 C.H.R.R. D/276, 59 Admin. L.R. (4th) 1, (sub nom. *Council of Canadians with Disabilities v. VIA Rail Canada Inc.*) [2007] 1 S.C.R. 650 (S.C.C.) — followed

Statutes considered:

Alberta Energy and Utilities Board Act, R.S.A. 2000, c. A-17

Generally — referred to

Business Corporations Act, R.S.O. 1990, c. B.16

Generally — referred to

s. 127(3)(d) — considered

Electricity Act, 1998, S.O. 1998, c. 15, Sched. A

s. 29 — considered

s. 142 — referred to

Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sched. B

Generally — referred to

Pt. IV — referred to

s. 1(1) — considered

s. 1(1) ¶ 1 — considered

s. 1(1) ¶ 2 — considered

s. 23(1) — considered

s. 36(3) — considered

s. 44(1) — considered

s. 78 — considered

s. 78(2) — considered

s. 78(3) — considered

s. 128(1) — considered

APPEAL by board from judgment reported at *Toronto Hydro-Electric System Ltd. v. Ontario (Energy Board)* (2008), 93 O.R. (3d) 380, 2008 CarswellOnt 5372, 298 D.L.R. (4th) 231, 53 B.L.R. (4th) 48 (Ont. Div. Ct.), allowing appeal by corporation regarding terms of dividend payments.

***J. MacFarland J.A.*:**

1 This is an appeal with leave of this court from the order of the Divisional Court (Kiteley, Swinton JJ., Lederman J. dissenting) dated September 9, 2008. The court declared that the Ontario Energy Board exceeded its jurisdiction and erred in law when it imposed, as a condition in its rate decision for 2006, a duty on Toronto Hydro-Electric System Limited to obtain the approval of a majority of its independent directors before declaring any future dividends payable to its affiliates (the "condition").

Overview

2 Toronto Hydro-Electric System Limited ("THESL") is an electricity distributor licensed and regulated by the Ontario Energy Board ("OEB"). THESL is a wholly-owned subsidiary of Toronto Hydro Corporation ("THC"). All of the shares of THC are owned by the City of Toronto (the "City").

3 In 2004-2005, THC paid over $116 million to the City in the form of dividends and interest payments. THC

funded a significant part of these payments through substantial annual increases in dividends from THESL and by charging THESL an above-market rate of interest on an inter-company loan. At the time THESL made the payments it had not completed a capital plan for reinvestment in its aging infrastructure.

4 When THESL applied to the OEB for approval of its distribution rates to be effective May 2006, the OEB expressed concern about the level of dividend payments and the above-market rate of interest being paid by THESL. Evidence before the OEB disclosed that the City anticipated a significant shortfall in its 2006 operating budget; that the City regarded THC as "a revenue source in the 2006 operating budget"; and that the City demanded substantial increases in dividends from THC which, in turn, demanded increased dividends from THESL.

5 The OEB is the regulator of Ontario's electricity industry, and is statutorily mandated to "protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service." The OEB manages this mandate primarily by setting just and reasonable rates.

6 In its decision, the OEB disallowed as a regulatory expense any interest charges above market rates, and required a majority of THESL's independent directors to approve any future dividend payments. In reaching this decision, the OEB noted that if a utility like THESL was to pay all of its retained earnings to its shareholders, this could adversely affect its credit rating, which in turn could harm ratepayer interests by causing higher costs and degradation in services. THESL appealed this decision.

7 In the Divisional Court, THESL argued that the OEB had no jurisdiction to impose the condition it did, either by statute or at common law, and further that the imposition of such a condition represented an unwarranted and indeed unlawful restriction on the authority of the board of directors to declare a dividend.

8 The majority in the Divisional Court accepted THESL's position on both bases advanced, allowed the appeal and set aside the part of the OEB decision that imposed the condition.

9 The OEB argues that the majority of the Divisional Court panel failed to appreciate and distinguish the principles that govern regulated utilities like THESL, which operate as monopolies, from those that apply to private sector companies, which operate in a competitive market. The OEB submits that this distinction is critical because whereas the directors and officers of an unregulated company have a fiduciary obligation to act in the best interests of the company (which usually equates to the interests of the shareholders), a regulated utility must operate in a manner that balances the interests of the utility's shareholders against the interests of its ratepayers. If a utility fails to operate in this way, it is incumbent on the OEB to intervene in order to strike this balance and protect the interests of ratepayers.

10 For the reasons that follow I would allow the appeal, set aside the order of the Divisional Court and restore the part of the rate decision that imposed the condition.

11 The issue for this court is whether the OEB had the ability, as part of its 2006 rate decision, to require THESL to obtain the approval of a majority of its independent directors before declaring any dividends.

Analysis

12 This court has held that the OEB is a highly specialized expert tribunal with broad authority to regulate the energy sector in Ontario and to balance competing interests: see *Natural Resource Gas Ltd. v. Ontario (Energy Board)* (2006), 214 O.A.C. 236 (Ont. C.A.), at para. 18.

13 The analysis must begin with the legislation that establishes the OEB and gives the OEB its powers. The OEB's objectives in respect of electricity are stated in s. 1 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15,

Sch. B (the "Act"):

Boards objectives, electricity

1.(1) The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.

2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.[FN1]

14 In short, the OEB is to balance the interests of ratepayers in terms of prices and service while at the same time ensuring a financially viable electricity industry that is both economically efficient and cost effective.

15 The *Electricity Act, 1998*, S.O. 1998, c. 15, Sch. A, requires a distributor of electricity to sell electricity to every person connected to the distributor's distribution system (s. 29). However, the distributor can only charge for the distribution of electricity in accordance with an order of the OEB. Section 78 of the Act provides in part:

78(2) No distributor shall charge for the distribution of electricity or for meeting its obligations under section 29 of the *Electricity Act, 1998* except in accordance with an order of the Board, which is not bound by the terms of any contract.

. . . . .

(3) The Board may make orders approving or fixing just and reasonable rates for the transmitting or distributing of electricity and for the retailing of electricity in order to meet a distributor's obligations under section 29 of the *Electricity Act, 1998*.

16 In relation to its ability to make orders the Act provides:

23(1) The Board in making an order may impose such conditions as it considers proper, and an order may be general or particular in its application.

17 In order to determine the appropriate standard of review, the inquiry must begin with a consideration of the nature of the OEB's decision.

I. Avoiding the "Jurisdiction" Trap

18 In recent years administrative law has undergone a significant transformation. Ever since Dickson J. championed the notion of increased deference to specialized administrative tribunals in *C.U.P.E., Local 963 v. New Brunswick Liquor Corp.*, [1979] 2 S.C.R. 227 (S.C.C.) ("*CUPE*"), courts have sought to avoid labelling matters as jurisdictional where such a label might lead to a more searching review of the administrative decision than is appropriate in the circumstances. In *New Brunswick (Board of Management) v. Dunsmuir*, [2008] 1 S.C.R. 190 (S.C.C.), Bastarache and LeBel JJ. underlined the importance of *CUPE* in this regard at para. 35:

Prior to *CUPE*, judicial review followed the "preliminary question doctrine", which inquired into whether a tribunal had erred in determining the scope of its jurisdiction. By simply branding an issue as "jurisdictional", courts could replace a decision of the tribunal with one they preferred, often at the expense of a legislative intention that the matter lie in the hands of the administrative tribunal. *CUPE* marked a significant turning point in the approach of courts to judicial review, most notably in Dickson J.'s warning that courts "should not be alert to brand as jurisdictional, and therefore subject to broader curial review, that which may be doubtfully so" (p. 233). Dickson J.'s policy of judicial respect for administrative decision making marked the beginning of the modern era of Canadian administrative law.

19 Support for the *CUPE* conceptualization of jurisdiction is also found in the majority reasons of Abella J. in *VIA Rail Canada Inc. v. Canadian Transportation Agency*, [2007] 1 S.C.R. 650 (S.C.C.), at paras. 88-89:

> The Federal Court of Appeal also concluded that the standard for reviewing the Agency's decision on the issue of whether an obstacle is undue, is patent unreasonableness. I agree. I do not, however, share the majority's view that VIA raised a preliminary, jurisdictional question falling outside the Agency's expertise that was, therefore, subject to a different standard of review. Applying such an approach has the capacity to unravel the essence of the decision and undermine the very characteristic of the Agency which entitles it to the highest level of deference from a court — its specialized expertise. It ignores Dickson J.'s caution in [*CUPE*] that courts "should not be alert to brand as jurisdictional, and therefore subject to broader curial review, that which may be doubtfully so".
>
> *If every provision of a tribunal's enabling legislation were treated as if it had jurisdictional consequences that permitted a court to substitute its own view of the correct interpretation, a tribunal's role would be effectively reduced to fact-finding.* Judicial or appellate review will "be better informed by an appreciation of the views of the tribunal operating daily in the relevant field". Just as courts "should not be alert to brand as jurisdictional, and therefore subject to broader curial review, that which may be doubtfully so", so should they also refrain from overlooking the expertise a tribunal may bring to the exercise of interpreting its enabling legislation and defining the scope of its statutory authority. [Emphasis added; citations omitted.]

20 Genuine questions regarding the boundaries of administrative authority under statute do arise. Administrative bodies must be correct in answering these questions. It is crucial to distinguish, however, between these "true" matters of jurisdiction and the wider understanding of jurisdiction that Dickson J. rebuked in *CUPE*. This point was highlighted by Bastarache and LeBel JJ. in *Dunsmuir* at para. 59:

> Administrative bodies must also be correct in their determinations of true questions of jurisdiction or *vires*. We mention true questions of *vires* to distance ourselves from the extended definitions adopted before *CUPE*. It is important here to take a robust view of jurisdiction. We neither wish nor intend to return to the jurisdiction/preliminary question doctrine that plagued the jurisprudence in this area for many years. *"Jurisdiction" is intended in the narrow sense of whether or not the tribunal had the authority to make the inquiry. In other words, true jurisdiction questions arise where the tribunal must explicitly determine whether its statutory grant of power gives it the authority to decide a particular matter.* The tribunal must interpret the grant of authority correctly or its action will be found to be *ultra vires* or to constitute a wrongful decline of jurisdiction. An example may be found in *United Taxi Drivers' Fellowship of Southern Alberta v. Calgary (City)*, [2004] 1 S.C.R. 485. In that case, the issue was whether the City of Calgary was authorized under the relevant municipal acts to enact bylaws limiting the number of taxi plate licences. That case involved the decision-making powers of a municipality and exemplifies a true question of jurisdiction or *vires*. These questions will be narrow. We reiterate the caution of Dickson J. in *CUPE* that reviewing judges must not brand as jurisdictional issues that are doubtfully so. [Emphasis added; citations omitted.]

21 David Phillip Jones and Anne S. de Villars offer a helpful analysis of the difference between the "narrow" and "wide" meaning of jurisdiction in their text, *Principles of Administrative Law*, 5th ed. (Toronto: Carswell, 2009) at pp. 140-41:

> In its broadest sense, "jurisdiction" means the authority to do every aspect of an *intra vires* action. In a narrower sense, however, "jurisdiction" means the power to commence or embark on a particular type of activity. A defect in jurisdiction "in the narrow sense" is thus distinguished from other errors - such as a breach of a duty to be fair, considering irrelevant evidence, acting for an improper purpose, or reaching an unreasonable result - which take place *after* the delegate has lawfully started its activity, but which cause it to leave or exceed its jurisdiction.
>
> . . . . .
>
> It is important to remember that virtually all grounds for judicial review of administrative action depend upon an attack on some aspect of the delegate's jurisdiction (in the wider sense) to do the particular activity in question. Consequently, it is equally important to remember that any behaviour which causes the delegate to *exceed* its jurisdiction is just as fatal as any error which means that it never had jurisdiction "in the narrow sense" even to commence the exercise of its jurisdiction. [Italics in original; footnotes omitted.]

22 Further guidance in terms of defining exactly what constitutes "true" questions of jurisdiction can be gleaned from the reasons of Abella J. in *VIA Rail*. At para. 91, she cited *Pasiechnyk v. Saskatchewan (Workers' Compensation Board)*, [1997] 2 S.C.R. 890 (S.C.C.), at para. 18, for the proposition that "[t]he test as to whether the provision in question is one that limits jurisdiction is: was the question which the provision raises one that was intended by legislators to be left to the exclusive decision of the Board?" In the same paragraph, Abella J. also referred to *Syndicat national des employés de la commission scolaire régionale de l'Outaouais v. U.E.S., local 298*, [1988] 2 S.C.R. 1048 (S.C.C.), at p. 1087, where Beetz J. held that "the only question which should be asked [is], 'Did the legislator intend the question to be within the jurisdiction conferred on the tribunal?'"

23 Thus, the focus is on discerning legislative intent with respect to the scope of a tribunal's authority to undertake an inquiry. This reading is consistent with Bastarache and LeBel JJ.'s observation that "[d]eference will usually result where a tribunal is interpreting its own statute or statutes closely connected to its function, with which it will have particular familiarity" (*Dunsmuir* at para. 54), and Abella J.'s conclusion that "[a] tribunal with the power to decide questions of law is a tribunal with the power to decide questions involving the statutory interpretation of its enabling legislation" (*VIA Rail* at para. 92). It also accords with Jones and de Villars observation at p. 146:

> [A] conscious and clearly-worded decision by the legislature to use a subjective or open-ended grant of power has the effect of widening the delegate's jurisdiction and, therefore, narrowing the ambit of judicial review of the legality of its actions.

24 Courts should hesitate to analyze the decisions of specialized tribunals through the lens of jurisdiction unless it is clear that the tribunal exceeded its statutory powers by entering into an area of inquiry outside of what the legislature intended. If the decision of a specialized tribunal aims to achieve a valid statutory purpose, and the enabling statute includes a broad grant of open-ended power to achieve that purpose, the matter should be considered within the jurisdiction of the tribunal. Its substance may still be reviewed for other reasons - on either a reasonableness or correctness standard - but it does not engage a true question of jurisdiction and cannot be quashed on the basis that the tribunal could not "make the inquiry" or "embark on a particular type of activity". In contrast, where a tribunal is pursuing an illegitimate objective, or is engaging in actions that clearly defy the limits of its statutory authority, then a reviewing court may properly declare its decisions to be *ultra vires*. These principles are consistent with Abella J.'s reasoning in *VIA Rail* at para. 96:

> It seems to me counterproductive for courts to parse and recharacterize aspects of a tribunal's core jurisdiction... in a way that undermines the deference that jurisdiction was conferred to protect. By attributing a jurisdiction-limiting label, such as "statutory interpretation" or "human rights", to what is in reality a function assigned and

properly exercised under the enabling legislation, a tribunal's expertise is made to defer to a court's generalism rather than the other way around.

II. Broad Powers of the OEB

25 The case law suggests that the OEB's power in respect of setting rates is to be interpreted broadly and extends well beyond a strict construction of the task.

26 For example, in *Advocacy Centre for Tenants-Ontario v. Ontario Energy Board* (2008), 293 D.L.R. (4th) 684 (Ont. Div. Ct.), the majority of the court held that the OEB had the jurisdiction to establish a rate affordability assistance program for low-income consumers purchasing the distribution of natural gas from the utility. Section 36(3) of the Act states that "[i]n approving or fixing just and reasonable rates, the Board may adopt any method or technique it considers appropriate." In paras. 53-56, the majority noted the breadth of the OEB's rate-setting power when its actions were in furtherance of the statutory objectives:

> [T]he Board is authorized to employ "any method or technique that it considers appropriate" to fix "just and reasonable rates."... the Board must determine what are "just and reasonable rates" within the context of the objectives set forth in s. 2 of the *Act*. Objective #2 therein speaks to protecting "the interests of consumers with respect to prices."
>
> .....
>
> [T]he Board in the consideration of its statutory objectives might consider it appropriate to use a specific "method or technique" in the implementation of its basic "cost of service" calculation to arrive at a final fixing of rates that are considered "just and reasonable rates." This could mean, for example, to further the objective of "energy conservation", the use of incentive rates or differential pricing dependent upon the quantity of energy consumed. As well, to further the objective of protecting "the interests of consumers" this could mean taking into account income levels in pricing to achieve the delivery of affordable energy to low income consumers on the basis that this meets the objective of protecting "the interests of consumers with respect to prices."
>
> The Board is engaged in rate-setting within the context of the interpretation of its statute in a fair, large and liberal manner.

27 The jurisdiction of the OEB was also reviewed in *Enbridge Gas Distribution Inc. v. Ontario (Energy Board)* (2005), 74 O.R. (3d) 147 (Ont. C.A.). In *Enbridge*, the OEB issued a rule permitting the gas vendor to determine who will bill its customers for the gas they buy from a vendor and for its transportation to them by the distributor. The appellants argued that this rule went beyond the jurisdiction conferred on the OEB by s. 44(1) of the Act, which provides that the OEB may make rules "governing the conduct of a gas distributor as such conduct relates to [a gas vendor]". Goudge J.A. ultimately found that the OEB had the jurisdiction to issue the rule. He endorsed a broad understanding of the Act in paras. 27-28:

> [The appellants] say that the intention of this subsection is to limit the Board's jurisdiction to a rule governing only the part of a gas distributor's conduct that relates to its business relationship with a gas vendor, such as when the gas vendor acts as agent on behalf of its gas supply customer to arrange with the gas distributor for delivery of that gas supply to that customer. ...
>
> In my view, there is nothing in either the language of s. 44(1)(b) or its statutory context to suggest such a narrow interpretation. ... Moreover, such a narrow reading would be inconsistent with the broad purpose of the Act, which is to regulate all aspects of the gas distribution business, not simply those aspects that involve a direct business relationship with gas vendors.

28 A recent decision from the Divisional Court offers further support for the proposition that the OEB enjoys a wide ambit of power in its rate-setting function. In *Toronto Hydro-Electric System Ltd. v. Ontario (Energy Board)* (2009), 252 O.A.C. 188 (Ont. Div. Ct.), leave to appeal to Ont. C.A. refused, the OEB allocated THESL's net after-tax gains on the sale of three properties to reduce THESL's revenue requirement, and thereby also reduce electricity distribution rates to ratepayers. The court unanimously held that the proper approach to a review of the OEB decision did not involve a "true" jurisdictional analysis as contemplated in *Dunsmuir*. Rather, a reasonableness standard applied because the decision in the case - whether and how the OEB may allocate the net after-tax gains on the sale of properties to reduce THESL's revenue requirement - was squarely within the rate-setting authority of the OEB and went to very core of the OEB's mandate. The court noted the expansive content of the rate-setting power at para. 17:

> An OEB decision may well engage or impact principles of corporate law, given that it regulates incorporated distributors, but the nature of the issue must be viewed in light of the regulatory scheme. While the decision in this case may have the effect of curtailing the appellant's ability to otherwise distribute or invest the net after tax gains from the sale of the properties, the substance of the OEB's decision relates to whether and how to apply those gains in its rate setting formula. Unlike the cases relied upon, this issue directly relates to the OEB's determination of rates and goes to the heart of its regulatory authority and expertise. There is no dispute that the OEB has rate-setting powers under the *OEBA* which are broad enough to encompass the power to determine reduced revenue requirements as a result of the sale of non-surplus assets. Although there is no privative clause, the OEB is a highly specialized expert tribunal with broad authority to regulate the energy sector in Ontario and to balance competing interests. [Citations omitted.]

29 The present appeal does not engage a "true" question of jurisdiction. As confirmed above, the Act is to be interpreted broadly. It is clear that the legislative intent of s. 78 of the Act is that the OEB have the principal responsibility for setting electricity rates. The Act specifies that in carrying out its responsibilities the OEB *shall* be guided by the objectives in s. 1(1), which include protecting the interests of customers with respect to prices and the adequacy, reliability and quality of electricity service. The Act also permits the OEB in making an order, to impose such conditions as *it* considers proper, and states that these conditions may be general or particular in application (s. 23(1)). Thus, the legislation reflects a clear intent by legislators to use both a subjective and open-ended grant of power to enable the OEB to engage in the impugned inquiry in the course of rate setting.

30 Further, it is apparent that as part of its rate-setting function, the OEB was entitled to consider the history of THESL's dividend payments. This was part of the inquiry into whether and how to control outgoing cash flows from THESL in order to ensure adequate capital. This line of inquiry goes to the heart of the OEB achieving its statutory objectives. In its reasons, the OEB noted that at the hearing there was considerable discussion of the dividend issue and that information concerning the dividend payouts had been filed. An inquiry into dividend payments was an inquiry that all parties believed was within the OEB's jurisdiction. The "true" nature of the respondent's challenge cannot be characterized as a matter of jurisdiction. Of course, it does not follow that the methods chosen are insulated from review (see Part IV).

III. The ATCO Decision

31 THESL argues that the Supreme Court of Canada's recent decision in *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, [2006] 1 S.C.R. 140 (S.C.C.), militates in favour of reviewing OEB decisions using a correctness standard. *ATCO* involved an application by ATCO to have the sale of a property approved by the Alberta Energy and Utilities Board as required by the statute. The Board approved the sale and imposed a condition requiring that a certain portion of the sale proceeds be allocated to rate-paying customers. The *Alberta Energy Board Utilities Act* set out that with respect to an order, the Board may "impose any additional conditions that the Board considers necessary in the public interest".

32 Writing on behalf of three other justices, Bastarache J. divided the inquiry into two questions. The first question was whether the Board had the power pursuant to its enabling statutes to allocate the proceeds from the sale of the utility's asset to its customers when approving the sale. The second question was whether the Board was permitted to allocate the proceeds of the sale in the way that it did. Bastarache J. concluded that the first question was to be reviewed on a correctness standard and the second question was to be reviewed on a more deferential standard.

33 This case is distinguishable from *ATCO*. The statutory grant of power in *ATCO* to "impose any additional conditions that the Board considers necessary in the public interest" is different than the statutory grant of power in this case. Bastarache J. referred to this provision as vague, elastic, and open-ended. In the present case, the OEB's imposition of a condition it considers proper (s. 23(1)) has to be guided by the legislated objectives set out in s. 1(1). These objectives are not vague, elastic, and open-ended. To the extent that there is uncertainty with respect to the achievement of the s. 1(1) objectives, that is a matter undeniably within the expertise of the OEB. Further, unlike the *ATCO* provision, the objectives in the Act require that the OEB protect the interests of *both* the customer and the utility.

34 There are four other factors that support distinguishing *ATCO* from this case. First, the decision in *ATCO* reveals that Bastarache J. reasoned that *ATCO* was not a rate-setting case. He noted that the provision granting the power to impose conditions could not be read in isolation. Rather, he explained that the provision had to be considered within the context of the purpose and scheme of the legislation. Bastarache J. stated that the main purpose of the Board is rate setting. The allocation of the sale proceeds did not fit within the limits of the powers of the Board, which "are grounded in its main function of fixing just and reasonable rates ('rate setting') and in protecting the integrity and dependability of the supply system" (para. 7).

35 Second, at para. 30, Bastarache J. determined that the Board's protective role -safeguarding the public interest in the nature and quality of the service provided to the community by public utilities by ensuring that utility rates are always just and reasonable- did not come into play. This factor pointed to a less deferential standard of review. In the present case, the OEB's "protective role" was central to the dividend condition.

36 Third, Bastarache J., viewed the issue in *ATCO* as the Board's power to transfer proprietary rights in the assets of the utility to the customers. In this case, the dividend condition did not result in the transfer of proprietary rights.

37 Fourth, in giving examples of conditions that could attach to the approval of a sale, Bastarache J. stated at para. 77 that the Board "could also require as a condition that the utility reinvest part of the sale proceeds back into the company in order to maintain a modern operating system that achieves the optimal growth of the system." As will be explained, the OEB placed the condition on the payment of dividends to ensure that dividends would not be paid when there was insufficient capital for plant maintenance.

IV. Reviewing the Exercise of OEB Jurisdiction: The Reasonableness Standard

38 Having determined that the OEB did not exceed its statutory grant of power, the question remains whether it could order that the declaration of a dividend requires the approval of the majority of THESL's independent directors. This question is reviewable on a reasonableness standard.

39 Recently, a reasonableness standard was used by this court in *Natural Resource Gas Ltd. v. Ontario (Energy Board)* (2006), 214 O.A.C. 236 (Ont. C.A.). The case arose from the application by a gas distributor seeking an order increasing its rate over a 12-month period, in order to allow for the recovery of unrecorded costs which were the result of an accounting error. Writing for the panel, Juriansz J.A. reviewed some of the recent appellate jurisprudence and concluded that reasonableness was the appropriate standard of review as the question was one of mixed

fact and law, and also involved policy considerations:

> In two recent decisions, *Graywood Investments Ltd. v. Toronto Hydro-Electric System*, [2006] O.J. No. 2030 (C.A.) and *Enbridge Gas Distribution Inc. v. Ontario (Energy Board)*, [2006] O.J. No. 1355 (C.A.), this court has considered the standard of review of decisions of the OEB.
>
> In *Enbridge*, while the result did not turn on the standard of review, Doherty J.A. did note (at para. 17) that the OEB had advanced a "forceful argument that the standard of review should, at the highest, be one of reasonableness".
>
> In *Graywood*, MacPherson J.A. recognized the expertise of the OEB in general (at para. 24):
>
>> First, the OEB is a specialized and expert tribunal dealing with a complicated and multifaceted industry. Its decisions are, therefore, entitled to substantial deference.
>
> In order to take this case outside the application of this general conclusion, [the distributor] must establish that the nature of the question in dispute and the relative expertise of the OEB regarding that question are different in this case than in *Graywood*. [At paras. 7-10.]
>
> . . . . .
>
> It is clear that the Act constitutes the OEB as a specialized expert tribunal with the broad authority to regulate the energy sector in Ontario. In carrying out its mandate, the OEB is required to balance a number of sometimes competing goals. On the one hand, it is required to protect consumers with respect to prices and the reliability and quality of gas service, but on the other hand, it is to facilitate a financially viable gas industry. The legislative intent is evident: the OEB is to have the primary responsibility for setting gas rates in the province.
>
> The Act does not contain a privative clause. Section 33 provides a right of appeal to the Divisional Court from an order of the OEB "only upon a question of law or jurisdiction". [At paras. 18-19.]
>
> . . . . .
>
> While the question does involve the meaning of the phrase "just and reasonable", it requires the application of that phrase to the particular and unusual facts of this case. The question is one of mixed fact and law and involves policy considerations as well. The OEB possesses greater expertise relative to the court in determining the question.
>
> Consequently, I conclude that the OEB's decision is reviewable on a standard of reasonableness. [At paras. 23-24.]

40 The facts of this case do not warrant departure from the reasonableness analysis. In my view, the nature of the OEB decision - structuring a condition that will protect the long-term integrity of THESL's energy infrastructure - falls squarely within the category of "mixed fact and law" with "policy considerations".

41 One of the reasons given by the majority below for applying a correctness standard was because the case dealt with principles of corporate law. When dealing with a regulated corporation the fact that corporate law principles are at play does not alone suggest a correctness standard of review. Corporate law principles will often be engaged when making decisions in respect of regulated corporations. It is the regulator's duty to use its expertise to apply corporate law principles within the context of its objectives; this implies a reasonableness standard.

V. Is the Decision a Reasonable One?

42 At para. 47 of Dunsmuir, Bastarache and LeBel JJ. described the two inquiries involved in assessing the reasonableness of a decision:

> Reasonableness is a deferential standard animated by the principle that underlies the development of the two previous standards of reasonableness: certain questions that come before administrative tribunals do not lend themselves to one specific, particular result. Instead, they may give rise to a number of possible, reasonable conclusions. Tribunals have a margin of appreciation within the range of acceptable and rational solutions. A court conducting a review for reasonableness inquires into the qualities that make a decision reasonable, referring both to the process of articulating the reasons and to outcomes. *In judicial review, reasonableness is concerned mostly with the existence of justification, transparency and intelligibility within the decision-making process. But it is also concerned with whether the decision falls within a range of possible, acceptable outcomes which are defensible in respect of the facts and law.*
>
> [Emphasis added.]

43 The first inquiry of the reasonableness analysis is into the "existence of justification, transparency and intelligibility within the decision-making process." The second inquiry is "concerned with whether the decision falls within a range of possible, acceptable outcomes which are defensible in respect of facts and law." Thus, the first inquiry deals with the justification process as articulated in the reasons for the decision and the second inquiry looks at the outcome. As noted in Dunsmuir, the reasonableness analysis will concern mostly the first inquiry.

(a) Justification, transparency and intelligibility

44 The inquiry into the justification, transparency and intelligibility of the decision-making process is focused on the reasons for the decision. In an oft-cited passage from *Ryan v. Law Society (New Brunswick)*, [2003] 1 S.C.R. 247 (S.C.C.), Iacobucci J. at para. 55 articulated the relationship between the reasons of a tribunal and the ultimate reasonableness of its decision:

> A decision will be unreasonable only if there is no line of analysis within the given reasons that could reasonably lead the tribunal from the evidence before it to the conclusion at which it arrived. If any of the reasons that are sufficient to support the conclusion are tenable in the sense that they can stand up to a somewhat probing examination, then the decision will not be unreasonable and a reviewing court must not interfere. *This means that a decision may satisfy the reasonableness standard if it is supported by a tenable explanation even if this explanation is not one that the reviewing court finds compelling.* [Emphasis added; citations omitted.]

45 Further, as Abella J. explained in *Via Rail* at para. 104:

> Where an expert and specialized tribunal has charted an appropriate analytical course for itself, with reasons that serve as a rational guide, reviewing courts should not lightly interfere with its interpretation and application of its enabling legislation.

46 And as more recently noted by Binnie J. in *Khosa v. Canada (Minister of Citizenship & Immigration)*, [2009] 1 S.C.R. 339 (S.C.C.), at para. 59:

> Reasonableness is a single standard that take its colour from the context. ... [A]s long as the process and the outcome fit comfortably within the principles of justification, transparency and intelligibility, it is not open to a re-

viewing court to substitute its own view of a preferable outcome.

and at para. 63:

> *Dunsmuir* thus reinforces in the context of adjudicative tribunals the importance of reasons, which constitute the primary form of accountability of the decision-maker to the applicant, to the public and to a reviewing court.

47 The OEB's reasons provide an intelligible explanation for the condition. The reasons both disclose a concern relating to "prices and the adequacy, reliability and quality" of service and explain how the chosen remedy will help to alleviate this concern.

48 Before addressing these two elements, it is important to note one factor about the context of the decision. THESL is what has been described as a "regulated monopoly". As Bastarache J. explained in *ATCO* at para. 3, "utility regulations exist to protect the public from monopolistic behaviour and the consequent inelasticity of demand while ensuring the continued quality of an essential service". In other words, the OEB's regulatory power is designed to act as a proxy in the public interest for competition: see *Advocacy Centre for Tenants-Ontario*. Because there is no competition, THESL could easily pass on the expense of business decisions to ratepayers through increased utility prices, or through the degradation of the quality of service, without the usual risk of losing customers. As was explained in para. 39 of *Advocacy Centre for Tenants-Ontario*, "[t]he Board's mandate through economic regulation is directed primarily at avoiding the potential problem of excessive prices resulting because of a monopoly distributor of an essential service."

49 While THESL is incorporated, as is required by s. 142 of the *Electricity Act*, under the provisions of the *Business Corporation Act*, R.S.O. 1990, c. B.16, ("*OBCA*") it is publicly regulated rather than a private corporation. This distinction is an important one. As Lederman J. noted in his dissenting reasons in the court below at para. 78:

> At the heart of a regulator's rate-making authority lies the "regulatory compact" which involves balancing the interests of investors and consumers. In this regard, there is an important distinction between private corporations and publicly regulated corporations. With respect to the latter, in order to achieve the "regulatory compact", it is not unusual to have constraints imposed on utilities that may place some restrictions on the board of directors. That is so because the directors of utility companies have an obligation not only to the company, but to the public at large.

50 The principles that govern a regulated utility that operates as a monopoly differ from those that apply to private sector companies, which operate in a competitive market. The directors and officers of unregulated companies have a fiduciary obligation to act in the best interests of the company (which is often interpreted to mean in the best interests of the shareholders) while a regulated utility must operate in a manner that balances the interests of the utility's shareholders against those of its ratepayers. If a utility fails to operate in this way, it is incumbent on the OEB to intervene in order to strike this balance and protect the interests of the ratepayers.

51 The decision reveals that the OEB was concerned about the aging plant and the lack of necessary capital. At the hearing it was argued that there appeared to be underinvestment in the physical plant over the past several years (para. 4.4.1). Evidence was presented that 30 to 40 per cent of the plant in service had exceeded its expected life (para. 4.5.3). The Board concluded that increased capital spending was required to address the issues of the aging plant (para. 4.7.1) and to maintain system reliability (para. 4.10.8).

52 However, despite the need for capital, the evidence was that there was a very dramatic increase in the dividend payouts in 2004 and 2005. As the OEB noted at para. 6.4.1, "[t]he level of dividends appears to be greater than the net income of the utility over at least a two year period." At para. 6.4.4 the OEB explained why these events were of concern:

> The question arises as to whether the Board should restrict the dividend payout by the utility. To the extent a utility pays all of its retained earnings to the shareholder, it will become more dependent on borrowing and this may have an adverse effect on its credit rating.

53 In sum, the OEB was concerned because THESL was paying THC very large dividends even though increased capital spending was going to be needed to maintain system reliability. THESL was either going to ignore its aging infrastructure or have to borrow funds to address it. Both courses of conduct would ultimately, as the OEB explained, have adverse effects on ratepayers. Lederman J. effectively summarized these circumstances at paras. 80 and 85:

> The setting of rates will accomplish little in terms of public protection if the revenue can be stripped out of the company without any controls.
>
> .....
>
> The OEB had evidence before it that THESL was paying increased dividends and an above market rate of interest while it was under investing by about $60 million in its capital expenditures. The OEB noted that if a utility like THESL was to pay all its retained earnings to its shareholder, this could adversely impact its credit rating, which in turn, could cause higher costs and degradation in service to electricity consumers.

54 The OEB also explained how it reached the conclusion that an appropriate response to the concerns raised by the substantial dividend payouts, was to require that any dividend paid by THESL be approved by a majority of its independent directors.

55 At the time of the hearing, the composition of the board of directors of THESL was identical to the THC. The reasons reveal that the OEB was very concerned about the about the relationships between THESL, THC, and the City. For example, at para. 3.2.3 the OEB questioned the percentage of THC's costs recovered from THESL:

> It is readily apparent to the Board that allocating these costs based on gross revenues produces an unwarranted bias against the ratepayers. The revenues of the utility are inflated by the high cost of wholesale power. That is an ever increasing amount. Because these costs are increasing, it does not follow the utility's share of the overhead costs should be increasing. In short, there is no necessary relationship between the revenue share and the share of overhead cost.

56 The reasons also discuss the above-market interest rate THESL was paying the THC on a loan (s. 5.3), as well as the purchase of the City's street lighting business (para. 6.4.3). According to the OEB, the above-market interest rate resulted in THESL paying approximately an additional $16 million per year which was being borne by the ratepayers. Amplifying the concern was the City's decision after the hearing, but before the decision was released, to extend the loan to 2013. This led the OEB to note at para. 5.3.8, it is "apparent that the financing decisions are being made unilaterally by the City, which is the sole shareholder of the utility."

57 With respect to dividends, as already noted, the OEB was concerned about the very dramatic increase in the dividend payouts in 2004 and 2005. At para. 5.3.18 the OEB stated:

> *Nor is it any defence to say this is not a decision of the utility but is being made unilaterally by the City of Toronto. That is exactly the problem. In fact it could be argued that this is part of a pattern.* The City has extracted extensive dividends from this utility in recent years. It is likely one of the rare occurrences in Canadian financial markets where the level of dividends exceeds the net income. [Emphasis added.]

58 Moreover, the OEB was aware of a change in a shareholder direction and the payment of special dividends. These facts are referred to in para. 6.4.2:

> At one time, there was a shareholder direction that limited the dividend payout to 40% of the utility's income, but that was changed to 50% of consolidated income. Moreover, it appears that were special dividends over and above that amount.

59 Thus, the OEB was of the opinion that one of the reasons for the THESL's unusual dividend payouts was the THC's, and ultimately the City's, control over THESL's decision making. The OEB explained at paras. 6.4.5 and 6.4.6 of the decision:

> A related question is the independence of the directors. The evidence in the hearing is that the directors of the utility and the parent, Toronto Hydro Corporation are currently identical.
>
> And none of the members of management are to be on the Board. This is an unusual situation.
>
> There is a requirement that at least one third of the directors of the distributor must be independent but that rule will not apply to this utility until July 1, 2006. In the course of these hearings the utility has confirmed that it will comply with the requirement and at that time, the independent directors will be appointed.

60 Concern about affiliate transactions is not unique to THESL. The decision notes that there is extensive jurisprudence in gas cases with respect to transactions between a regulated utility and an affiliate (para. 5.3.17). The OEB has also established the *Affiliate Relationship Code for Electricity Distributors and Transmitters* ("*ARC*") with a separate compliance procedure to guard against harm to ratepayers that may arise as a result of dealings between a utility and its affiliates. One of the provisions of the *ARC* required that one third of the board of directors of a distributor be independent from any affiliate by July 1, 2006. It is evident that independence is viewed as a guard against harmful decisions that arise as a result of dealings between a utility and its affiliates.

61 Following this line of reasoning, the Board concluded at paras. 6.4.7 to 6.4.9 that the condition was needed to balance the interests of *both* the customer and the shareholder:

> Given the unusual high level of dividend payout and the concern expressed by a number of parties, the Board believes that it is appropriate that any dividend paid by the utility to the City of Toronto should be approved by a majority of the independent directors.
>
> Much of the controversy in this case has been dominated by discussion about non arms length transaction between the utility and the City of Toronto, whether it relates to dividend payouts, payment of interest on loans or the purchase of goods and services. *The introduction of independent directors will be a step in the right direction. The requirement that independent directors approve dividend payouts to affiliates will give the public greater assurance that the interests of ratepayers are not subservient to those of the shareholders.* The Board believes this is in keeping with the policy intent of Section 2 of the ARC.
>
> This provision will be reviewed by the Board in the next rate case. At a minimum it will signal the Board's serious concern with the state of inter-affiliate relations. [Emphasis added.]

62 For the reasons set out above, this was a reasonable decision.

(b) Acceptable Outcomes

63 To reiterate, the second inquiry in a reasonableness analysis is that the decision fall "within a range of possible, acceptable outcomes which are defensible in respect of the facts and law." It is in this part of the analysis where, in my opinion, this court should address THESL's argument that the imposed condition violated corporate law.

64 THESL argued at the Divisional Court, and argues before this court, that the OEB order was contrary to settled principles of corporate law that the directors of a public company cannot delegate their power to declare dividends. Section 127(3)(d) of the *OBCA* confirms this prohibition by expressly excluding any delegation of the board of directors' power to declare a dividend from the general rule permitting delegation to a managing director or committee of directors.

65 The OEB submits that the authority to approve dividends was not taken away from the directors. Approval by the entire board is still required before a dividend can be issued. The independent directors are simply an additional check on the authority of the full board. The OEB also relies on s. 128(1) of the Act which provides that, "[i]n the event of a conflict between this Act and any other general or special act, this Act prevails."

66 The majority judgment below accepted THESL's argument, and found that the OEB had effectively delegated the power to declare dividends to the majority of the independent directors contrary to the *OBCA* and long-standing corporate law principles.

67 In dissenting reasons, Lederman J. accepted the submission of the OEB - that the order leaves the discretion to declare a dividend in the hands of THESL's directors, albeit with an additional check by THESL's independent directors.

68 In the context of a regulated corporation, I agree with Lederman J. As he explained at para. 81, "the OEB has crafted a reasonable and less intrusive remedy that balances the interests of THESL's shareholder and its ratepayers and is consistent with the 'regulatory compact'."

Conclusion

69 For these reasons, I would allow the appeal, set aside the order of the Divisional Court and in its place make an order in accordance with these reasons. In the circumstances, I would not order costs.

***K. Feldman J.A.*:**

I agree.

***S.E. Lang J.A.*:**

I agree.

Appeal allowed.

FN1 On September 9, 2009, three additional objectives were added to s. 1(1).

END OF DOCUMENT

TAB 8

DATE: 20060721
DOCKET: C44333

COURT OF APPEAL FOR ONTARIO

LASKIN, BORINS and JURIANSZ JJ.A.

BETWEEN:	
NATURAL RESOURCE GAS LIMITED	**Alan Mark and Jennifer Teskey for the appellant**
Appellant	
- and -	
ONTARIO ENERGY BOARD	**Glenn Zacher for the respondent**
Respondent	
	Heard: April 28, 2006

On appeal from the order of the Divisional Court dated April 21, 2005.

JURIANSZ J.A.:

I. Introduction

[1] Natural Resource Gas Limited ("NRG") appeals from a decision of the Divisional Court dated April 21, 2005, dismissing its appeal of the Review Decision of the Ontario Energy Board (the "OEB") dated April 19, 2004.

[2] NRG purchases gas from producers and distributes it to its customers at rates regulated by the OEB. Because of an accounting error, NRG had unrecorded costs of purchasing gas in the amount of $531,794 during the period from October 1, 2002 to December 31, 2003. Had these costs been recognized, they would have been passed on to NRG's customers in the normal course. After an initial unsuccessful application, NRG made a second application to the OEB on January 20, 2004 in which it sought authorization to record the unrecorded costs as a debit as of January 1, 2004 and an order allowing the recovery of the unrecorded costs by increasing its rates over a twelve month period commencing May 1, 2004. The OEB's Review Decision on that application is the subject of this appeal.

[3] In that decision, the OEB found the unrecorded costs were material and had been prudently incurred and therefore NRG should be permitted to recover them. The OEB also decided that NRG's recovery of the costs would be deferred over three years to minimize rate volatility to customers. Then, in what gives rise to this appeal, the OEB went on to decide that NRG would not be allowed to recover any of its regulatory costs or the interest charges associated with the deferral of the recovery of the unrecorded costs.

[4] NRG contends that the interest and regulatory expenses result not from the accounting error but from the OEB's decision to defer recovery the unrecorded costs. NRG submits that since the OEB decided that the unrecorded costs were prudently incurred, it follows that the expenses that are associated with the OEB's decision to defer recovery are also prudently incurred. NRG asserts that as a matter of law it would not be "just and reasonable" to deny their recovery.

[5] I would dismiss the appeal because the OEB's decision satisfies the applicable standard of review: reasonableness.

II Issues on Appeal

1. What is the standard of review that applies to the OEB's decision?
2. Did the OEB commit reversible error by denying NRG recovery of its regulatory costs and interest charges?

III Standard of Review

[6] The Divisional Court applied a standard of reasonableness: "[I]n view of the lack of a privative clause, the OEB's disposition attracts at least a standard of reasonableness." NRG submits the Divisional Court erred and that the proper standard of review of the OEB's decision in this case is correctness.

[7] In two recent decisions, *Graywood Investments Ltd. v. Toronto Hydro-Electric System*, [2006] O.J. No. 2030 (C.A.) and *Enbridge Gas Distribution Inc. v. Ontario (Energy Board)*, [2006] O.J. No. 1355 (C.A.), this court has considered the standard of review of decisions of the OEB.

[8] In *Enbridge*, while the result did not turn on the standard of review, Doherty J.A. did note (at para. 17) that the OEB had advanced a "forceful argument that the standard of review should, at the highest, be one of reasonableness".

[9] In *Graywood*, MacPherson J.A. recognized the expertise of the OEB in general (at para. 24):

> First, the OEB is a specialized and expert tribunal dealing with a complicated and multi-faceted industry. Its decisions are, therefore, entitled to substantial deference.

[10] In order to take this case outside the application of this general conclusion, NRG must establish that the nature of the question in dispute and the relative expertise of the OEB regarding that question are different in this case than in *Graywood.*

[11] *Graywood* concerned a dispute as to whether the parties had agreed that Toronto Hydro would install an electricity distribution system in a Graywood building project before November 1, 2000. This case concerns whether the OEB's decision to deny recovery of certain regulatory and interest expenses is "just and reasonable". I am satisfied the nature of these questions is sufficiently different that it is necessary to address the standard of review that applies in this case afresh. That *Graywood* was not available to the parties when this case was argued provides additional reason to do so.

[12] Determining the applicable standard of review requires a pragmatic and functional consideration of four factors:

> i) the existence of a privative clause;
>
> ii) the expertise of the tribunal;
>
> iii) the purpose of the statute as a whole, and the provision in particular; and
>
> iv) the nature of the question in dispute.
>
> *Pushpanathan v Canada (Minister of Citizenship and Immigration)*, [1998] 1 S.C.R. 982, at paras. 29-38.

[13] These factors, in my view, need not be analysed separately or in any particular order. I address all four factors in the following general discussion

[14] The OEB derives its authority from the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Sched. B (the "*Act*").

[15] The objectives of the OEB with respect to gas regulation are set out in section 2 of the *Act*:

> 2. The Board, in carrying out its responsibilities under this or any other Act in relation to gas, shall be guided by the following objectives:
>
> > 1. To facilitate competition in the sale of gas to users.

2. To protect the interests of consumers with respect to prices and the reliability and quality of gas service.

3. To facilitate rational expansion of transmission and distribution systems.

4. To facilitate rational development and safe operation of gas storage.

5. To promote energy conservation and energy efficiency in a manner consistent with the policies of the Government of Ontario.

5.1 To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.

6. To promote communication within the gas industry and the education of consumers. 1998, c. 15, Sched. B, s. 2; 2002, c. 23, s. 4 (2); 2003, c. 3, s. 3; 2004, c. 23, Sched. B, s. 2.

[16] The OEB also has a broad rule-making regulatory jurisdiction:

44.(1) The Board may make rules,

(a) governing the conduct of a gas transmitter, gas distributor or storage company as such conduct relates to its affiliates;

(b) governing the conduct of a gas distributor as such conduct relates to any person,

(i) selling or offering to sell gas to a consumer,

(ii) acting as agent or broker for a seller of gas to a consumer, or

(iii) acting or offering to act as the agent or broker of a consumer in the purchase of gas;

(c) governing the conduct of persons holding a licence issued under Part IV;

(d) establishing conditions of access to transmission, distribution and storage services provided by a gas transmitter, gas distributor or storage company;

(e) establishing classes of gas transmitters, gas distributors and storage companies;

(f) requiring and providing for the making of returns, statements or reports by any class of gas transmitters, gas distributors or storage companies relating to the transmission, distribution, storage or sale of gas, in such form and containing such matters and verified in such manner as the rule may provide;

(g) requiring and providing for an affiliate of a gas transmitter, gas distributor or storage company to make returns, statements or reports relating to the transmission, distribution, storage or sale of gas by the gas transmitter, gas distributor or storage company of which it is the affiliate, in such form and containing such matters and verified in such manner as the rule may provide;

(h) establishing a uniform system of accounts applicable to any class of gas transmitters, gas distributors or storage companies;

(i) respecting any other matter prescribed by regulation. 1998, c. 15, Sched. B, s. 44 (1).

[17] The provision in issue is s. 36 of the *Act*. It prohibits a gas distributor from selling gas or charging for its distribution except in accordance with an order of the OEB and provides that the OEB is not bound by the terms of the contract. It authorizes the OEB to approve or fix "just and reasonable rates" for the sale, transmission, distribution and storage of gas. It allows the OEB, in approving or fixing just and reasonable rates, to adopt any method or technique that it considers appropriate. At the time it provided in part:

36 (1) No gas transmitter, gas distributor or storage company shall sell gas or charge for the transmission, distribution or storage of gas except in accordance with an order of the Board, which is not bound by the terms of any contract.

> (2) The Board may make orders approving or fixing just and reasonable rates for the sale of gas by gas transmitters, gas distributors and storage companies, and for the transmission, distribution and storage of gas.
>
> (3) In approving or fixing just and reasonable rates, the Board may adopt any method or technique that it considers appropriate.
>
> ...

[18] It is clear that the Act constitutes the OEB as a specialized expert tribunal with the broad authority to regulate the energy sector in Ontario. In carrying out its mandate, the OEB is required to balance a number of sometimes competing goals. On the one hand, it is required to protect consumers with respect to prices and the reliability and quality of gas service, but on the other hand, it is to facilitate a financially viable gas industry. The legislative intent is evident: the OEB is to have the primary responsibility for setting gas rates in the province.

[19] The Act does not contain a privative clause. Section 33 provides a right of appeal to the Divisional Court from an order of the OEB "only upon a question of law or jurisdiction".

[20] NRG would characterize the question at issue as one of law, namely, the definition of the phrase "just and reasonable" as used in section 36 of the Act. NRG submits that, properly interpreted, the words "just and reasonable" require that a utility be allowed to recover all its legitimate, prudently incurred costs. NRG argues that the OEB, having found that the unrecorded costs were prudently incurred but not initially recognized because of an accounting error, cannot disallow interest costs that result not from the accounting error, but from the OEB's decision to defer recovery over three years.

[21] The OEB suggests that the question is one involving the manner in which the OEB exercised its discretion in fixing NRG's rates.

[22] The Divisional Court described the nature of the question in this way:

> The question before the Board was therefore not simply whether recovery of costs prudently incurred should be allowed, as the appellant characterized it. The matter was compounded by the added issue of how to deal with the accumulation of costs caused by the appellant's inadvertence. The Board determined that customers must pay the prudently

> incurred unrecorded costs of the appellant, but the impact of recovery of the accumulated total should be ameliorated by allowing recovery over three years. The accumulated cost of the time over which recovery from customers would be required and the appellant's regulatory costs ... must be borne by the appellant. That issue was not a question of law but one involving fact-finding, policy considerations, rate-setting expertise, and law.

[23] I agree. While the question does involve the meaning of the phrase "just and reasonable", it requires the application of that phrase to the particular and unusual facts of this case. The question is one of mixed fact and law and involves policy considerations as well. The OEB possesses greater expertise relative to the court in determining the question.

[24] Consequently, I conclude that the OEB's decision is reviewable on a standard of reasonableness.

IV <u>Is the Decision in This Case Reasonable?</u>

[25] The Supreme Court of Canada, in *Law Society of New Brunswick v. Ryan*, [2003] S.C.R. 247, explained (at 270) what the reasonableness standard requires of a reviewing court:

> A decision will be unreasonable only if there is no line of analysis within the given reasons that could reasonably lead the tribunal from the evidence before it to the conclusion at which it arrived. If any of the reasons that are sufficient to support the conclusion are tenable in the sense that they can stand up to a somewhat probing examination, then the decision will not be unreasonable and a reviewing court must not interfere.

[26] NRG submits that, as a matter of law, rates that deny utilities recovery of their legitimate prudently incurred costs cannot be "just and reasonable". Rates must be "just and reasonable" to utilities as well as to consumers. Utilities cannot be expected to provide service if they are not allowed to recover their costs and a fair return.

[27] NRG relies on the decision of the Federal Court of Appeal in *TransCanada Pipelines Limited v. National Energy Board*, [2004] F.C.J. No. 654 (C.A.). Under its governing legislation, the National Energy Board's authority to determine just and reasonable tolls, like that of the OEB, is not limited by any statutory directions. Rothstein J.A. indicated that the impact on customers or consumers could not be a factor

in the determination of the utility's cost of equity capital. However, any resulting increase could be so significant that it would be proper for the Board to phase in the tolls over time provided there was no economic loss to the utility. He said (at para. 43), "In other words, the phased in tolls would have to compensate the utility for deferring recovery of its cost of capital."

[28] I do not read the OEB's decision to be inconsistent with the proposition that a utility must be allowed to recover all of its prudently incurred costs. The OEB, upon concluding that the unrecorded gas costs had been prudently incurred, allowed NRG to recover them. However, the OEB did not accept the premise of NRG's position on this appeal — that if the unrecorded gas costs were prudently incurred, it must logically follow that the regulatory costs to recover them and the interest costs associated with the deferral of their recovery were also prudently incurred. Rather, the OEB found the accumulation of these costs was attributable to NRG's failures to properly record them and to discover its error promptly:

> We are surprised and disappointed with the time that it took NRG to realize that its PGCVA mechanism was incorrect, which exposed the utility and its customers to unnecessary risk and created a difficult situation for the customers and the Board. However, we accept that the misrecording was the result of error, not a purposeful action by NRG.

[29] The OEB went on to observe:

> Had NRG recorded the gas cost variances properly in the PGCVA, the present conundrum would have been avoided.
>
> ... we find the NRG's error has resulted in a substantial and avoidable accumulation of potential customers' charges, through no fault of the customers.

[30] These factual findings of the OEB are not open to question on appeal. In light of these findings, the OEB said, "[W]e must therefore look for a balance". The OEB struck that balance in the following terms:

> Considering the need for NRG to recover its prudently incurred unrecorded gas costs and mitigating the impact on customers, as well as not creating undue inter-generational inequity, we find that a reasonable balance is recovery of the $531,794 amount over a three year period, in equal portions, without interest.

[31] The OEB went on to say that NRG could not recover its regulatory costs incurred in the proceeding.

[32] On my reading, the OEB took the view that NRG's regulatory costs were not prudently incurred. That view is reasonable. But for NRG's accounting error and the delay in recognizing it, NRG would not have had to incur costs to seek and obtain the OEB's decision to permit recovery of the unrecorded costs.

[33] NRG emphasizes that it did not seek recovery of any interest charges from the time the costs were not recorded to the date of the OEB's decision finding the costs to have been prudently incurred. Therefore it submits that the interest charges it claims are the direct result of the OEB's decision to rate-smooth and not of NRG's accounting error.

[34] In my view, it was open to the OEB to consider the underlying as well as the direct cause of the interest charges. The OEB said, "It is also our view that customers should not be burdened by any interest charges that would not have accrued had the customers been presented with the appropriate timely billing". While the interest charges directly result from the OEB's decision to defer their recovery, the OEB would not have faced the situation that prompted that decision "had NRG recorded the gas costs variances properly" and there had been no "substantial and avoidable accumulation of potential customers' charges". Rather, the "present conundrum could have been avoided".

[35] The line of analysis from the OEB's findings of fact to the conclusion it reached is reasonable. It's balancing of the various considerations and interests before it lies at the heart of its function and expertise. Its reasons withstand a probing analysis.

V <u>Disposition</u>

[36] I would find that the OEB's decision was reasonable and dismiss NRG's appeal.

[37] The parties indicated they would make efforts to resolve the issue of costs. If they are unable to do so they make written submissions through the court's senior legal officer.

"R.G. Juriansz J.A."
"I agree J. Laskin J.A."
"I agree S. Borins J.A."

RELEASED: July 21, 2006

TAB 9

Ontario Energy Board Act, 1998

S.O. 1998, CHAPTER 15
SCHEDULE B

Board objectives, electricity

1. (1) The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.
2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.
3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.
4. To facilitate the implementation of a smart grid in Ontario.
5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities. 2004, c. 23, Sched. B, s. 1; 2009, c. 12, Sched. D, s. 1.

Board's powers, general

Power to determine law and fact

19. (1) The Board has in all matters within its jurisdiction authority to hear and determine all questions of law and of fact. 1998, c. 15, Sched. B, s. 19 (1).

Order

(2) The Board shall make any determination in a proceeding by order. 1998, c. 15, Sched. B, s. 19 (2); 2001, c. 9, Sched. F, s. 2 (1).

Reference

(3) If a proceeding before the Board is commenced by a reference to the Board by the Minister of Natural Resources, the Board shall proceed in accordance with the reference. 1998, c. 15, Sched. B, s. 19 (3).

Additional powers and duties

(4) The Board of its own motion may, and if so directed by the Minister under section 28 or otherwise shall, determine any matter that under this Act or the regulations it may upon an application determine and in so doing the Board has and may exercise the same powers as upon an application. 1998, c. 15, Sched. B, s. 19 (4).

Exception

(5) Unless specifically provided otherwise, subsection (4) does not apply to any application under the *Electricity Act, 1998* or any other Act. 1998, c. 15, Sched. B, s. 19 (5).

Jurisdiction exclusive

(6) The Board has exclusive jurisdiction in all cases and in respect of all matters in which jurisdiction is conferred on it by this or any other Act. 1998, c. 15, Sched. B, s. 19 (6).

Codes that may be incorporated as licence conditions

70.1 (1) The Board may issue codes that, with such modifications or exemptions as may be specified by the Board under section 70, may be incorporated by reference as conditions of a licence under that section. 2003, c. 3, s. 48.

TAB 10

Statutory Powers Procedure Act

R.S.O. 1990, CHAPTER S.22

Power to review

21.2(1)A tribunal may, if it considers it advisable and if its rules made under section 25.1 deal with the matter, review all or part of its own decision or order, and may confirm, vary, suspend or cancel the decision or order. 1997, c. 23, s. 13 (20).

TAB 11

ONTARIO ENERGY BOARD
Rules of Practice and Procedure

(Revised November 16, 2006, July 14, 2008 and October 13, 2011)

PART VII - REVIEW

42. Request

42.01 Subject to Rule 42.02, any person may bring a motion requesting the Board to review all or part of a final order or decision, and to vary, suspend or cancel the order or decision.

42.02 A person who was not a party to the proceeding must first obtain the leave of the Board by way of a motion before it may bring a motion under Rule 42.01.

42.03 The notice of motion for a motion under Rule 42.01 shall include the information required under Rule 44, and shall be filed and served within 20 calendar days of the date of the order or decision.

42.04 Subject to Rule 42.05, a motion brought under Rule 42.01 may also include a request to stay the order or decision pending the determination of the motion.

42.05 For greater certainty, a request to stay shall not be made where a stay is precluded by statute.

42.06 In respect of a request to stay made in accordance with Rule 42.04, the Board may order that the implementation of the order or decision be delayed, on conditions as it considers appropriate.

43. Board Powers

43.01 The Board may at any time indicate its intention to review all or part of any order or decision and may confirm, vary, suspend or cancel the order or decision by serving a letter on all parties to the proceeding.

43.02 The Board may at any time, without notice or a hearing of any kind, correct a typographical error, error of calculation or similar error made in its orders or decisions.

44. Motion to Review

44.01 Every notice of a motion made under **Rule 42.01**, in addition to the requirements under **Rule 8.02**, shall:

(a) set out the grounds for the motion that raise a question as to the correctness of the order or decision, which grounds may include:

  (i) error in fact;

  (ii) change in circumstances;

  (iii) new facts that have arisen;

  (iv) facts that were not previously placed in evidence in the proceeding and could not have been discovered by reasonable diligence at the time; and

(b) if required, and subject to **Rule 42**, request a stay of the implementation of the order or decision or any part pending the determination of the motion.

45. Determinations

45.01 In respect of a motion brought under **Rule 42.01**, the Board may determine, with or without a hearing, a threshold question of whether the matter should be reviewed before conducting any review on the merits.