RP-1999-0044

IN THE MATTER OF the Ontario Energy Board Act, 1998;

AND IN THE MATTER OF an Application by Ontario Hydro Networks Company Inc., for an Order or Orders approving year 2000 transmission cost allocation and rate design.

BEFORE: Roger Higgin
Presiding Member

Paul Vlahos
Vice Chair

Brock Smith
Member

DECISION WITH REASONS

MAY 26, 2000

TABLE OF CONTENTS

1. INTRODUCTION

1.1 THE APPLICATION

1.1.1 Ontario Hydro Networks Company Inc. ("OHNC" or the "Applicant" or the "Company") is the regulated subsidiary of Ontario Hydro Services Company Inc. ("OHSC"). OHNC owns and operates the transmission and distribution businesses of OHSC. On May 1, 2000 OHNC was renamed Hydro One Networks Inc. In this Decision the Board will refer to the Applicant as OHNC.

1.1.2 OHNC filed an application (the "Application") dated October 1, 1999 with the Ontario Energy Board (the "Board") under sections 78 and 129 of the *Ontario Energy Board Act, S.O. 1998, c.15, Sch. B,* (the "Act"or the "OEB Act") for an order or orders approving a cost allocation and rate design proposal for the transmission of electricity. The rates and other charges for which approval was requested would be effective upon the declaration of open access by the Government of Ontario. The Board assigned file number RP-1999-0044 to the Application.

1.2 THE HEARING

1.2.1 The Board issued a Notice of Application dated October 8, 1999 and Procedural Order No. 1 dated November 12, 1999. Following Issues Day, on November 26, 1999 the Board issued Procedural Order No. 2 with the approved Issues List.

1.2.2 An Alternative Dispute Resolution (ADR) Settlement Conference was held from February 7 to February 9, 2000. A document entitled "Settlement Agreement" was filed with the Board on February 15, 2000. The Board informed the parties at the commencement of the hearing that, since none of the issues were completely settled, all issues, except those noted as argument only, should proceed to be heard in full.

1.2.3 The oral hearing commenced on February 16, 2000 and lasted until March 9, 2000. The Applicant submitted argument in chief on March 17, 2000. Intervenor argument was submitted on March 29, 2000 and the Applicant's reply on April 19, 2000.

1.2.4 The following parties and their representatives participated in the oral phase of the proceeding:

Ontario Hydro Networks Company Inc. (OHNC)	Don Rogers
AMOCO Petroleum Canada (AMOCO)	George Vegh
Association of Major Power Consumers in Ontario (AMPCO)	Jim Fisher
Coalition of Distribution Utilities (CDU)	Wendy Earle
Consumers Association of Canada (CAC)	Robert Warren
Collingwood PUC (Collingwood Hydro), Detroit Edison Company, Electrical Contractors Association of Ontario (ECAO)	Erik Goldsilver
Energy Cost Management Inc. (ECMI) on behalf of certain distribution utilities	Roger White
Energy Probe Foundation (Energy Probe)	Mark Mattson
EnergyLink Power Corporation (EnergyLink)	Harold Wong

Chiefs of Ontario Anishinabek Nation, Union of Ontario Indians, Fort William First Nation, Batchewana First Nation, Windigo First Nation (the Chiefs)	Carol Godby Paul Vogel
Green Energy Coalition (GEC)	David Poch
Imperial Oil Limited (Imperial Oil)	Sharon Wong
Independent Power Producers Association of Ontario (IPPSO)	David Brown
Municipal Electric Association (MEA)	Kelly Friedman Alan Mark
Northwatch	Lloyd Greenspoon
Ontario Federation of Agriculture (OFA)	Ted Cowan
Ontario Mining Association (OMA), Inco Limited (Inco)	Rick Coburn
Ontario Power Generation Inc. (OPG)	Bruce Campbell
Pollution Probe Foundation (Pollution Probe)	Murray Klippenstein
Power Workers Union (PWU)	Richard Stevenson
Sunoco Inc./Suncor Energy Inc. (Sunoco)	Ken Liddon
Toromont Energy (Toromont)	George Vegh
Toronto Hydro-Electric System Limited (Toronto Hydro)	Mark Roger

TransAlta Energy Corporation (TransAlta)	Peter Budd
TransCanada Energy Ltd. (TransCanada Energy)	Keith Rawson Bonnie Andriachuk
Vulnerable Energy Consumers Coalition (VECC)	Michael Janigan

1.2.5 The following parties did not participate in the oral hearing but submitted argument:

Enron Canada Corp. (Enron)
Federation of Ontario Cottagers' Associations (FOCA)
Five Nations Energy Inc. (Five Nations Energy)
Independent Electricity Market Operator (IMO)
Ontario Association of Physical Plant Administrators (OAPPA)
Ontario Natural Gas Association (ONGA)

1.2.6 The following parties intervened in the proceeding but did not actively participate: Aboriginal Resource Consortium; City of Thunder Bay; Competition Bureau; Direct Energy Marketing; ECNG Inc.; Enbridge Consumers Gas Ltd.; HealthPro Procurement Services Inc.; Heating, Ventilation, Air Conditioning Contractors Coalition Inc.; Marketing D'Energie HQ Inc; Markham Hydro Electric Commission; Natural Resource Gas Limited; Northland Power Inc.; Ottawa Hydro Electric Commission; PanCanadian Petroleum Limited; Placer Dome (CLA) Limited; Shaman Power Corporation; TransEnergie; Union Gas Limited; Upper Canada Energy Alliance.

<u>Witnesses</u>

1.2.7 The following witnesses testified in the oral hearing:

<u>For the Applicant:</u>

A. Poray	Manager, Pricing and Product Development

D. Curtis	Manager, Transmission Regulation
G. Schneider	Senior Advisor, Regulatory and Stakeholder Affairs Division

For OPG:

R. Osborne	President and CEO
B. Boland	Vice President, Regulatory Affairs
R. Orens	President, Energy and Environmental Economics Inc.

For AMPCO:

K. Snelson	President, Snelson International Energy
J. Townsend	Purchasing Manager Strategic Materials, Stelco
R. Baxter	Vice President, Kimberly Clarke Inc.
O. Bhatia	Vice President, Energy and International Customers, Abitibi Consolidated
D. Goldsmith	Manager, Planning & Development, IVACO Rolling Mills
J. LeMay	Project Manager Energy Conservation, Inco Limited
D. Campbell	Vice President and Resident Manager, Bowater Thunder Bay Operations
B. Aranha	Assistant Director of Purchasing and Logistics, Dofasco
D. Axford	Plant Manager, Amherstburg, CXY Chemicals

For AMOCO:

J-P. Desrochers	Regional Director
J. Thompson	NGL Business Development
P. Cahill	Plant Superintendent, Sarnia Fractionation Plant

For Imperial Oil:

B. Fischer	Senior Vice President, Products and Chemical Division and Director
P. Roach	Manager, Utilities and Technical Services

M. McEachen	Business Unit Leader for Infrastructure

For GEC:

P. Chernick	President, Resource Insight Inc.

For Northwatch:

K. Rabago	Managing Director, Corporate Consulting, Rocky Mountain Institute

For IPPSO:

A. Barnstaple	Past President, IPPSO
P. Andres	Owner/Operator, Sustainable Energy Link
B. Ander	Director, Business Development, Toromont Energy
R. Fagan	Senior Associate, Tabors Caramanis & Associates

For EnergyLink:

H. Wong	President

For TransAlta:

W. Taylor	Director, Regulatory Affairs
S. Hodgkinson	Director, Business Development

For Pollution Probe:

J. Gibbons	Senior Economic Advisor, Canadian Institute for Environmental Law & Policy

For Chiefs of Ontario:

T. Bressette	Regional Chief of Ontario
M. Seabrook	Member, Red Rock First Nation
D. Kelly	Member, Onegaming First Nation
B. Crofts	Independent Consultant
D. Drinkwalter	Independent Consultant
B. LeClair	Economic Development Officer, Pic River First Nation

1.2.8 Copies of all the evidence, exhibits and argument filed in the proceeding, together with a verbatim transcript of the hearing are available for review at the Board's offices. While the Board has considered all of the evidence and submissions presented in this hearing, the Board has chosen to reference these only to the extent necessary to clarify specific issues on which it has made findings.

1.3 BACKGROUND TO TRANSMISSION COST ALLOCATION AND RATE DESIGN

1.3.1 The rates proposed in the Application are designed to recover the revenue requirement of $1.163 billion approved by the Board for the year 2000 in the Transitional Rate Order RP-1998-0001. This Board-approved fiscal year 2000 revenue requirement was adjusted to $1.182 billion effective January 1, 2000 by a Board Letter of Direction, dated March 1, 2000, to reflect an adjustment in the allowed return on common equity based on changes to the forecast of Long Canada Bond rates for the year 2000. The Company's evidence and all evidentiary references (except unless explicitly stated) in this Decision are based on the Board approved year 2000 revenue requirement of $1.163 billion prior to the above adjustment.

1.3.2 Prior to enactment of the *Energy Competition Act, 1998*, Ontario Hydro operated as an integrated electricity utility providing power to large direct customers, municipal electric utilities and rural/remote customers. Following a review by the OEB, the overall utility revenue requirement and rates were set by the Ontario Hydro Board of Directors.

1.3.3 The rates charged to the various rate classes were for *bundled service* comprising power generation/supply, delivery of power by the high voltage transmission grid to Direct industrial customers and Local Distribution Companies (LDCs), as well as distribution of low voltage electricity to over one million rural customers. Ontario Hydro also provided power to remote communities not connected to the transmission system. These communities are in northern Ontario and are largely supplied with power from diesel generating sets and some small hydro sites.

1.3.4 With the proclamation of Bill 35, Ontario Hydro has been restructured into a holding company - Ontario Hydro Financial Corporation - and two groups of operating companies - Ontario Power Generation Inc., a producer of power and Ontario Hydro Services Company, responsible for regulated transmission and distribution services as well as other unregulated affiliates providing energy related services. The system control responsibilities of Ontario Hydro have been transferred to the Independent Electricity Market Operator (IMO).

1.3.5 In its application (RP-1998-0001) for approval of its revenue requirements and cost of service for Transmission and Distribution for fiscal 1999 and 2000, OHNC indicated that rates would continue to be bundled until opening of the electricity market in the year 2000. However, that application also included a proposed transmission rate for post market opening based on classification of transmission assets into network and transformation and allocation of costs associated with the utility rate base and other components of the annual revenue requirement to the corresponding cost "pools".

1.3.6 In its RP-1998-0001 Decision and Order the Board directed the Company to file comprehensive cost allocation and rate design proposals for transmission no later than October 1, 1999. The Board also directed OHNC to consult with its stakeholders prior to filing its evidence in support of the Application. A large part of OHNC's pre-filed evidence dealt with the process and results of the consultation.

1.3.7 As noted earlier, the ADR process did not completely settle any of the issues. Although there was a narrowing of views on several issues, all issues proceeded to be heard in the oral hearing and/or argued in the argument phase. The issues are listed in the Table of Contents of this Decision under Chapters 2 (Cost Allocation) and 3 (Rate Design).

1.3.8 The Applicant noted throughout the proceeding that its proposals were in several cases compromises resulting from its stakeholder consultation process and reflected positions that "we could live with rather than necessarily our own preference". These compromise proposals were contested by several of the main intervenors who either supported other proposals that were considered by the Applicant and rejected, or put forward their own proposals.

1.3.9 On April 18, 1999 Toronto Hydro filed a Motion requesting *inter alia* that the issue of the Toronto Hydro Low Voltage Switchgear Credit (Switchgear Credit Issue) be added to the Issues List and a written hearing be held. Ottawa Hydro also requested Moving Party status in the Motion.

1.3.10 OHNC did not object to the addition of the Switchgear Credit Issue, but expressed concern that the Board's Decision on other issues should not be delayed as a result of hearing the matter.

1.3.11 On May 19, 2000 the Board issued its Decision on the Motion in which the Board granted the relief requested by the Moving Parties, but indicated that it would not delay its Decision on the other issues in the RP-1999-0044 proceeding and would issue a Procedural Order in due course.

2. <u>COST ALLOCATION</u>

2.0.1 This chapter deals with OHNC's proposals relating to cost allocation. The main issues requiring a Board decision are:

- the proposed cost allocation methodology;
- definition of the line connection pool; and
- treatment of customer buy-out of OHNC-owned line connection and transformation connection facilities.

2.1 COST ALLOCATION METHODOLOGY

2.1.1 OHNC functionalized transmission assets into the following eight functional groups:

Transmission - Network;
Transmission - Line Connection;
Transformation Connection;
Shared (Split) Functions;
Generation Connection - Network;
Common Function;
Meter Function; and
Other.

2.1.2 OHNC then allocated the above assets and associated costs to the following three pools:

- *Network*
- *Transformation*
- *Line Connection*

2.1.3 The transmission *network* system is the backbone of the transmission system that is used by all transmission customers and includes all of the 500 kV, 230 kV and 115 kV circuits that are normally operated in parallel with the 500 kV circuits. The network pool also contains the 345 kV, 230 kV and 115 kV connections with neighbouring jurisdictions and all transformation and switching stations performing a network function. Approximately $675 million in annual cost has been allocated to the network pool.

2.1.4 The *transformation* pool consists of all OHNC transformation facilities that step down voltages from above 50 kV to below 50 kV. Approximately $300 million in annual cost has been allocated to the transformation pool.

2.1.5 The *line connection* pool consists of the radial parts of the transmission system that emanate from the network facilities and connect customers to the transmission network. Approximately $190 million in annual cost has been allocated to the line connection pool.

2.1.6 Consideration was given to creating additional pools, such as generation connection and meters, but this was rejected by OHNC.

2.1.7 OHNC produced a detailed connectivity data base of power system assets. The connectivity database identifies linkages between OHNC transmission assets, and between the generation supply and load delivery points. The data base facilitated the categorization of transmission assets to functional groups and the association of assets and groups with financial and load information.

2.1.8 OHNC distributed costs into the three pools on the basis of either direct assignment or, when costs could not be directly assigned, by applying various cost allocation methodologies.

Positions of the Parties

2.1.9 In general, intervenors supported OHNC's cost allocation methodology and some provided other comments relating to cost allocation principles. These comments included references to the purposes of the OEB Act, cost causality and user pay principles and criticisms that OHNC relied on customer preferences rather than sound ratemaking principles. Several parties offered their own prescriptions for cost allocation principles that they submitted were more appropriate than those relied on by OHNC.

Board Findings

2.1.10 The Board accepts the Applicant's cost allocation model for the transmission system as reasonable. In making this finding the Board has considered the comments regarding the principles relied on by OHNC, but concluded that very little turns on these criticisms. The Board therefore accepts the Applicant's cost allocation methodology for setting transmission rates for the opening of the electricity market.

2.1.11 The Board found the specific information provided by the Company useful, in that the detailed listing of assets within the connectivity database provides transparency which facilitates testing by interested parties. The Board expects the Company to maintain this database. Also, the Board expects the Company to identify any changes that it wishes to make to its cost allocation methodology as approved by the Board in this Decision.

2.2 LINE CONNECTION POOL DEFINITION

2.2.1 OHNC defined *delivery points* as the points at which a transmission customer is connected to OHNC-owned transmission or transformation assets. Each delivery point attracts network charges and may also attract transformation charges, unless the customer owns the transformation assets. A customer that owns its line connections does not have its delivery point included in the line connection pool and is not assessed line connection charges if its line connection is connected to a network station. However, if a customer owns its own line connection assets that do not connect directly to a network station, but connect to a network line, the customer would still attract line connection charges due to OHNC's proposed dual function definition of network assets discussed below.

2.2.2 According to OHNC's evidence there are a total of 796 transmission delivery points (112 serving Direct industrial customers, 461 serving LDCs and 223 serving OHNC Distribution). Many of the delivery points are associated with high voltage network lines and network stations. OHNC has defined the line connection pool to include all delivery points that use OHNC assets to connect to the network stations. There are

660 delivery points in the proposed line connection pool. In some cases there are up to 6 parallel circuits that are radial and some connection lines are connected in series. Short (stub) connections from network circuits are also classified as line connections. The remaining 136 delivery points, serving 14 Directs, 83 LDCs and 39 OHNC Distribution are directly connected to network stations and do not attract line connection charges.

2.2.3 Some intervenors were concerned about the equity between certain customers who are connected directly to network stations, and all other customers that must pay a line connection charge to connect to the network station, even if the customer owns the line connection. This results from OHNC's proposed treatment of the dual function of certain network lines which operate to connect the delivery point to network stations (line connection mode) and also to provide network connection from one network station to another (network mode). The determination of this issue is also directly related to the incentive for customers to buy their existing line connections, or in future to build their own new line connections (discussed below).

Positions of the Parties

2.2.4 AMPCO disagreed with the OHNC definition of the line connection pool, which it characterized as a "broad" definition, implying that more line connection assets and costs should be assigned or allocated to the network pool leaving a "narrow" definition of line connection. Under AMPCO's proposed narrow definition, a line connection should only contain line connection assets that serve one transmission delivery point or that serve a group of delivery points providing power to the same directly connected transmission customer.

2.2.5 According to AMPCO, the OHNC definition, if not corrected, would lead to discrimination between customers who have paid for at least part of their line connection and those who have not. In addition, in AMPCO's view, the incentives for self-provision of line connections would be significantly weakened. On the other hand, with the narrow definition the assets in the line connection pool are dedicated to one directly connected transmission customer. That customer can be held responsible for the specific costs of those facilities and will have the opportunity to control the costs, subject to the necessary standards being met.

2.2.6 AMPCO submitted that its proposal for a narrow definition of the line connection pool prevents double charging by allowing customers who have paid for their dedicated line connection assets to avoid paying for the dedicated line connection assets of other customers through the line connection pool.

2.2.7 The impact of AMPCO's proposals is a shift of $130 million of the revenue requirement into the network pool, leaving $50.7 million in the line connection pool. The number of delivery points in the line connection pool would decrease from 660 to 45.

2.2.8 In MEA's view AMPCO's narrow definition does not adhere to the principles of cost causality and fairness as costs of facilities serving a limited number of customers would be shifted to all others. This would result in higher line connection charges to the larger LDCs remaining in the connection pool. MEA also noted that under AMPCO's proposal, a line connection shared by two LDCs would be moved from the network pool into the line connection pool if the LDCs merged. This is not the case for OHNC's proposal since it is based on the functionality of the assets. MEA noted that the line connection charges for large LDCs would be $20-$25 million greater if the narrow definition of line connection is adopted.

2.2.9 VECC supported the OHNC broad definition of the line connection pool and submitted that the narrow definition proposed by AMPCO was not founded on solid cost allocation principles. VECC expressed concern that the narrow definition would result in a significant cost shift from line connection into the network pool, resulting in a significant breakdown of the user pay principle and cost causality. It also noted that the narrow definition would represent a move away from postage stamp rate design principles.

2.2.10 Sunoco submitted that, under the narrow line connection definition, the line connection pool would be too small and have too few participants to work as an effective cost allocation mechanism. Sunoco asserted that the definition of the pools should be based on the functionality of the assets included, rather than the number of customers they serve. In Sunoco's view, OHNC's definition does this. The narrow pool definition would result in some customers paying twice, once for their line connection and again for the costs of the shared line connection facilities in the broadened network pool. The narrow line connection definition also causes a "huge" cost shift between customers that have delivery points in the line connection pool and those that do not. This cost shift would be aggravated over time as customers of the line connection pool for whom the acquisition cost is small, may elect to buy back their line connection assets.

2.2.11 PWU supported OHNC's broad definition and noted that the narrow definition would result in a line connection pool populated largely by LDCs and that the line connection costs of Direct industrial customers would be shifted into the network pool and paid for by all customers. It also noted that there are significant complexities with the narrow definition of the line connection pool.

2.2.12 IPPSO supported AMPCO's proposal. It also submitted that OHNC should be directed to file an application for approval of a separate pool for generation connection assets no later that the first quarter of 2001.

2.2.13 Inco supported AMPCO's proposals. Inco characterized OHNC's proposal as unfair to customers, such as Inco, that have contributed to all or part of the cost of their line connection.

2.2.14 Toromont supported AMPCO's narrow definition and noted that the network to line connection asset ratio was 78:22 in the RP-1998-0001 proceeding compared to OHNC's current 58:42 proposal. Toromont also argued that OHNC should be directed to create a wholesale metering pool which would encourage customers and wholesale market participants to provide their own metering.

2.2.15 GEC expressed concerns about the allocation of costs of line connection assets shared by (non-embedded) generators and loads. In particular, in GEC's view OHNC's proposal allocates a disproportionate amount of the costs to a generator whose capacity is significantly smaller than the load of the customer.

2.2.16 The Chiefs submitted that the introduction of specific line connection charges will disadvantage those customers located at greater distance from the network. In particular, the move to self-provision of line connection facilities would reduce the size of the pool and lead to big increases in costs for those customers remaining in the pool with longer line connections, such as First Nations. The Chiefs submitted that if a line connection pool is approved, First Nations communities should be excluded from it. The Chiefs also submitted that the costs associated with the 25 cycle system should be removed from the costs to be recovered from First Nations customers, and could also reduce costs for generation projects being considered by First Nations.

2.2.17 OHNC reiterated its support for its proposal arguing that the Board should accept the dual function of certain network lines which provide a specific line connection function. OHNC pointed out that, if the Board found that tapped delivery points to dual function lines should not attract line connection service charges, there are added complexities with respect to defining the threshold length for such a tap above which a delivery point would attract line connection charges. OHNC noted that there are over 50 delivery points with tap line lengths of 0.02 km to over 20 km connecting them to dual function lines that would need to be reallocated. OHNC also pointed out that the same threshold should also apply to delivery points that are connected to the network stations by OHNC-owned radial lines.

Board Findings

2.2.18 The Board notes the Applicant's evidence that, as the transmission system evolved, radial connection lines serving customers did not all originate at network stations and in many cases tapped into network lines. According to OHNC, from a functionality standpoint it is not possible to split the costs of dual purpose lines between network and line connection. For example, many of the 115 kV lines were originally built as network lines but are now classified as line connection assets serving one or more delivery points.

2.2.19 The evolution of the system created a disparity between those transmission customers who, because of historical and geographic circumstances, are served from the 136 delivery points connected directly to a network station and therefore would not pay line connection charges if they own the line, and customers who are served from the other 660 delivery points who are connected to the network stations via dual function lines and would pay a line connection charge even if they own, or have paid for the line connection portion.

2.2.20 In the Board's analysis there are several possible approaches to address this inequity. One approach is to find a way to allocate the costs of dual purpose lines between network and line connection. The Board recognizes, as OHNC stated, that this would be difficult because of various factors, including the changing functionality of the lines at different times.

2.2.21 Another approach would be to revert to the single network/line pool model that was used historically. This latter approach, which was not actively supported by any intervenor, may be viewed as a backward step and would also run counter to the Market Design Committee (MDC) recommendation of making the market for line connection contestable and allowing customers the option to develop their own line connections outside the OHNC pool.

2.2.22 A third approach would be to adopt the AMPCO proposal of a narrow line connection pool. However this proposal is not well developed and, in the Board's view, suffers from several major flaws. For example:

- It would exclude a large number of delivery points that, based on functionality, cannot be distinguished from those included in the narrow definition of the line connection pool without any criteria other than serving a single customer, that is connected to a network transmission line via a tap, to justify this exclusion. Based on OHNC's response to questions, 191 delivery points having similar functional characteristics should be added to the 45 included in the narrow line connection pool for a total of 236.

- The cross examination of AMPCO's witness also revealed significant definitional problems that unless resolved, would lead to inequity between similarly placed customers.

- There is also the need to determine the distance or configuration criteria by which a delivery point serving a single customer would qualify for inclusion/exclusion from the line connection pool.

2.2.23 However, one advantage of AMPCO's narrow definition is that there is a more appropriate cost causality between costs allocated to the redefined line connection pool and customers who use line connection assets. The Board also notes that such an approach is consistent with the MDC recommendation encouraging contestability of the line connection pool in the longer term.

2.2.24 The Board concludes that it does not have adequate evidence to assess the validity of any alternative definition of the line connection pool. Although the Board is not satisfied with OHNC's proposed definition of the line connection pool, the Board accepts this definition for the purpose of setting initial transmission rates until the next cost allocation/rate design proceeding. By that time, the Board expects OHNC to reconsider the definition of the line connection pool and either propose a modified definition, or be prepared to provide satisfactory reasons if it proposes to continue with the current definition.

2.3 BUY-OUT OF EXISTING CONNECTION ASSETS

2.3.1 The issue is whether customers should be allowed to buy their existing connection assets and at what price.

2.3.2 AMPCO and certain other parties advocated that customers should be allowed to buy their connection facilities and take control of upgrading the capacity of the connection and that the buy-out option be exercised at the Net Book Value of the assets. It argued that market value is not the appropriate price since customers have already paid for the assets. It also pointed out that a sale at Net Book Value would keep the pool whole.

2.3.3 MEA argued that AMPCO's proposal to allow customers to buy out their line connection facilities should also be rejected regardless of the transaction price. If customers with short line connections buy out and leave the line connection pool, this would increase the costs for others with longer, more costly line connections.

2.3.4 Toronto Hydro submitted that, in order for line connection facilities to be removed from the line connection pool, customers should be allowed to buy out their specific assets but not be required to buy out the assets up to the network station. To require this would be discriminatory and reduce the incentives for self-provision of line connections. The remaining assets (e.g. dual purpose network lines) should be added to the network pool.

2.3.5 OHNC submitted that the Board has no jurisdiction to force OHNC to sell assets. OHNC also submitted that the AMPCO proposal is "patently unfair". The pool contains assets for which the Net Book Value is lower than both replacement and historical cost. Sale at Net Book Value would result in "cherry picking" of assets and raise costs to existing customers which could lead to a winding down of the pool. In that regard, OHNC noted that there is general support for the pool concept.

2.3.6 OHNC also stated that the evolution of the line connection pool should be based on experience and judicious decisions that can only be made after some years of open access. A decision to wind down the line connection pool would, according to OHNC, be premature and contrary to government direction on uniform or postage stamp transmission pricing.

Board Findings

2.3.7 The regulatory implications of asset sales have been recently considered by the Board in the context of the restructuring of Ontario's gas utilities. The gas utilities applied for transfer to an affiliate of assets (e.g. water heaters) associated with their ancillary programs. In its various decisions the Board has adopted the following regulatory principles:

- The assets should be removed from the utility rate base at accounting Net Book Value.

- Any gain or loss from the sale is to the account of the shareholder.

- Any transaction costs should be borne by the shareholder, not the utility ratepayers.

2.3.8 In those transactions the assets in question were non-regulated assets, but included in rate base. The situation in this proceeding relates to the possible sale of regulated assets to the customers that these assets serve. The issue therefore in the Board's view is whether the principles established by the Board as noted above should apply here.

2.3.9 If the same principles applied to regulated assets as non-regulated assets, the concern is that utilities may remove assets at Net Book Value, sell them at a profit, and then replace them at the current higher cost which would increase the utility's revenue requirement. The Board is concerned that this would not be appropriate from a ratemaking perspective.

2.3.10 However, in this specific case the assets in question are dedicated to specific customer(s), and once sold would not require replacement. Therefore the Board finds that the principles for gas utilities noted above, shall apply to situations of sale or transfer of the line and transformation connection assets.

2.3.11 OHNC states in its argument that the Board does not have the jurisdiction to order the buy-out option. This may or may not be the case. In any event, it is unclear to the Board from the testimony and argument whether OHNC plans to make the buy-out option available to its transmission customers. The Board expects OHNC to clarify its policy in this regard and to report at its next cost allocation/rate design proceeding. The Board would be interested in the reasons OHNC would not be willing to encourage customers to take responsibility for their line and/or transformation connections individually or in the case of shared facilities, as a group.

3. RATE DESIGN

3.0.1 This chapter deals with the following rate design issues:

- Definition of a Transmission Customer;
- Net versus Gross Load Billing;
- Existing Embedded Generation;
- Charge Determinants and Related Matters;
- Treatment of New Load Connection Investment;
- Treatment of Generators;
- Requests for Special Rate Treatment; and
- Export and Wheel-through Transactions.

3.1 DEFINITION OF TRANSMISSION CUSTOMER

3.1.1 Under the former Ontario Hydro's Power District construct, the Direct industrial customers were grouped with former Ontario Hydro Retail, which distributed electricity to rural areas in Ontario (these customers are now being served by OHNC Distribution). The Power District was conceived in the Ontario Hydro rate structure primarily to allow the Direct industrial customers to have the diversity benefits similar to those enjoyed by customers of MEUs, given that demand charges were calculated on the basis of non-coincident peak.

3.1.2 OHNC pointed out that, following open access, OHNC Distribution cannot be treated differently than any other LDC, and therefore the Power District construct cannot be carried forward.

3.1.3 In the existing Ontario Hydro tariff structure, transmission customers are defined as all LDCs and those customers classified as Direct industrial customers. LDCs may be connected directly or indirectly (embedded LDCs) to the transmission system. Direct industrial customers are the 105 large users (demand exceeding 5 MW) that comprise (i) 69 customers connected to the transmission system directly; (ii) 34 customers connected to Ontario Hydro Retail (now OHNC Distribution); and (iii) two customers connected to the LDCs.

3.1.4 Having assessed a number of options, OHNC indicated a preference for transmission customers to be defined as those customers who are directly connected to the transmission system. However, it indicated that it is reluctant to adopt this definition at this time as there has been inadequate discussion with the various customer groups to assess the implications of that definition. In the interim, OHNC proposed continuing with the existing definition.

Positions of the Parties

3.1.5 In its prefiled evidence, AMPCO proposed that transmission customers, for network services, should be all wholesale market participants with loads in Ontario who schedule power through the IMO. This includes wholesale market participants embedded in an LDC. This construct was referred to as the "outer ring of wholesale meters". For connection services, AMPCO proposed that transmission customers are all wholesale market participants that are directly connected to the transmission system. This would exclude LDCs or other wholesale market participants embedded in an LDC. This was referred to as the "inner ring of wholesale meters".

3.1.6 OHNC's proposal was supported by OFA, PWU, MEA, CAC, VECC, Toronto Hydro and CDU. Included in the rationale for that support was the lack of analysis of the impacts of OHNC's preferred long term definition, and the importance of ensuring that the way in which distribution entities charge their customers for transmission service is consistent with the way in which wholesale customers are charged. In MEA's view, AMPCO's proposal is an effort to support its objectives of obtaining coincident peak demand billing.

3.1.7 FOCA was opposed to the short-term definition put forward by OHNC on the grounds that it shifts costs from MEUs to OHNC Distribution customers and former Direct industrial customers of Ontario Hydro. Adopting OHNC's preferred definition now would mitigate the cost shifting. The 34 Direct industrial customers and all smaller MEUs served from the OHNC Distribution lines would become distribution customers and share diversity benefits with all others served from the common distribution facilities. Similarly, all end-use customers served at 115 kV and 230 kV would no longer be customers of LDCs.

3.1.8 ECMI agreed with OHNC's short-term definition but opposed OHNC's long-term definition on the grounds that it is driven by rate stability considerations for OHNC itself, not rate stability for LDCs or end use customers.

3.1.9 IPPSO submitted that it is important to select a definition now and stated that OHNC has not shown any justification for delaying a move to its preferred definition. IPPSO suggested a transmission customer should be defined as any customer that is connected to the transmission system, as long as the pass-through of transmission charges to downstream customers with interval meters is done using the same charge determinant parameters as for all directly connected customers.

3.1.10 TransCanada Energy supported AMPCO's outer ring of meters proposal. In its view, OHNC's proposal does not provide equal treatment for market participants that are end-use customers and are connected to the transmission system. Also, it argued that an interim solution creates uncertainty for market participants.

3.1.11 The IMO supported an immediate move to OHNC's preferred definition. Five Nations Energy also supported the immediate implementation of OHNC's long-term definition on the basis that it would provide the most just, equitable and non-discriminatory treatment for those market participants that are directly connected to OHNC's transmission grid.

3.1.12 OFA and the Chiefs recommended retaining the Power District construct. The Chiefs also suggested that customers should be determined by the ownership of the distribution company serving them and that size should not be a criterion in a definition of transmission customer.

Board Findings

3.1.13 The Board recognizes that the definition of transmission customer is important for several reasons: the definition provides the basis for OHNC's rate setting; it is incorporated into IMO's billing, settlement, and reconciliation processes; and it will guide the rate setting of distribution utilities.

3.1.14 The Board agrees with OHNC that the Power District construct can no longer continue under open access, partly because it includes OHNC Distribution and also because it is based on an arbitrary classification of customers.

3.1.15 In the Board's view, proposals made for the definition of a transmission customer on the basis of explicit or implicit linkage to the definition of a wholesale customer are not necessary. The linkage is not necessary because the IMO can still calculate transmission charges payable by embedded large users on the basis of the rates, terms and conditions, for which OHNC and LDCs have obtained approval of the Board. Moreover, from the transmission utility's perspective, there ought to be a relatively high degree of stability in the design of transmission rates. For these reasons, the Board does not accept AMPCO's "outer ring of meters" definition.

3.1.16 The Board notes that OHNC prefers that transmission customers should be defined as those customers who are directly connected to the transmission system. The Board has not been persuaded that the results of further review, which according to OHNC may take up to three or four years, would be of such critical importance to offset the need for certainty during the current restructuring of the electricity sector, the enormity of which inevitably makes for a certain degree of "rough justice". The Board agrees with those intervenors who argued that the definition of a transmission customer should be settled now to provide certainty in the market and to avoid the necessity to redesign the IMO's billing and settlement system in the future.

3.1.17 The Board agrees that the direct connection criterion for defining a transmission customer is a clear, practical and unambiguous method of defining transmission customers. It is also widely used in other jurisdictions. The direct connection definition ensures objectivity and stability in setting transmission rates and revenue collection for OHNC, the LDCs and the IMO. The Board therefore directs OHNC to adopt its preferred long term definition upon market opening. A transmission customer shall be defined as being connected directly to the transmission system.

3.2 NET VERSUS GROSS LOAD BILLING

3.2.1 Generation that is not connected directly to the transmission system, and is located "behind the meter" that registers the electricity supplied from the regulated transmission facilities, is referred to as "embedded generation". Similarly, connection of any existing or new merchant generation to directly supply an LDC or other customer will also reduce the demand on the transmission system.

3.2.2 Given the largely fixed costs that characterize the transmission infrastructure, and in the absence of immediate prospects of replacing the lost demand, the issue is whether the load leaving the transmission system should continue to be charged for the sunk costs of the transmission system (gross load billing) or should not bear those sunk costs (net load billing).

3.2.3 Under net load billing, the charges for a transmission customer are calculated on the basis of a charge determinant that is measured on the meter(s) reading the load the customer draws from the regulated transmission system.

3.2.4 Under gross load billing, the charges for a transmission customer are calculated as under net load billing plus the charge determinant for the load supplied by any embedded generation.

3.2.5 The net versus gross load billing issue comes about largely because of the over capacity that currently exists on the OHNC transmission network system and the need to recover associated sunk costs. A number of intervenors filed evidence and/or testified on this issue and related matters. The evidence, testimony, and arguments were voluminous. There was a substantial similarity of themes including: rate making principles; issues of competition in the power market and the role of new generation; impact on customers; equity considerations; practices in other jurisdictions; impact on the physical characteristics of the transmission system; stranded costs; environmental considerations; and the Board's mandate and role.

Network Pool

3.2.6 Having assessed a number of options, OHNC proposed that, for the near future, existing load customers who install new embedded generation to serve all or part of their existing load should be billed for network pool charges on a gross load billing basis with a reduction to 50% of the full network rate for the amount of *efficient* embedded generation that displaces existing load. Load displaced with non-efficient generation would be based on gross load billing. OHNC provided a definition of what it considered new efficient generation, which gave rise to controversy related to the differences between the OHNC definition of efficient generation and that contained in the federal *Income Tax Act*. OHNC also proposed to exempt new embedded generation under 1 MW from gross load billing.

3.2.7 For the longer term, OHNC proposed to bring forward (within three years) for Board approval a contracting template that would provide the basis for OHNC and the customer to negotiate the specific rate and terms of individual new embedded generation projects.

3.2.8 OHNC estimated the impact on different customer groups from net versus gross load billing under several scenarios and assumptions. For example, with 2,550 MW (medium scenario) of new embedded generation coming on stream by year 2008, the "non-embedding" LDCs would experience an increase in their total transmission charges of 12.7% under net load billing for both network and connection, compared to gross load billing with no new embedded generation. The 20 largest "highly embedding" direct industrial customers on the other hand would experience a decrease of 44.7% in network and connection charges. Under the same scenario and assumptions, but with net load billing for network only, the impact on the "non-embedding" LDCs would be an increase of 7% and for the "highly embedding" 20 largest industrial customers the impact would be a decrease of 24.6%. Compared to gross load billing for both network and connection with no new embedded generation, the aggregate transmission rate to year 2008 was forecast by OHNC to increase by 7.1% under net load billing for network and gross load billing for connection. Under OHNC's 50% access fee proposal, the above impacts would be somewhat reduced.

Positions of the Parties

3.2.9 The prefiled evidence, testimony, and argument on net versus gross billing was extensive and polarized. Parties on either side of the issue used the same sections of the Act and the same regulatory principles to argue opposite positions. Although there was generally a recognition of OHNC's well-meaning attempts to find a middle ground, some felt that OHNC's proposals were self-serving, deficient or selective in applying widely-accepted rate making principles. The testimony given by some intervenors who are in the business of developing new generation was received by certain parties with skepticism. Moreover, some intervenors linked this issue and conditioned their position on a number of other cost allocation and rate design issues to be resolved in the proceeding, which added to the complexities the Board faced in deliberating on and addressing this issue, especially when certain parties appeared to alter somewhat their position during the argument phase.

3.2.10 At the heart of the issue is the concern, on the one hand, about cost responsibility and "cost shifting" among different groups of customers and, on the other hand, the desire to encourage the building of new generation providing the potential for both greater competition and developing more environmentally benign sources of electricity.

3.2.11 Gross load billing for network services was supported by groups representing small volume customers (CAC, VECC), and electricity distributors (largely represented by MEA and a few represented by ECMI and CDU). Gross load billing was also supported by PWU and Energy Probe.

3.2.12 OPG and Sunoco supported net load billing in principle but suggested alternative methods to those proposed by OHNC for addressing overcapacity of the transmission system and stranded costs. OPG proposed phasing-in net load billing over a ten year period on a project-by-project basis. Sunoco proposed a six year phase-in period from market opening.

3.2.13 TransAlta proposed a combination of the two billing methods. LDCs and OHNC Distribution would be billed on a gross load basis. Net load billing would apply to all end-use customers served by either OHNC Distribution or an LDC and any flows into an LDC's system be added back to the actual reading on the LDC's meter.

3.2.14 Net load billing was supported by large industrial customers represented by either AMPCO or appearing on their own (Inco, Imperial), certain large institutional customers represented by OAPPA, environmental groups (GEC, Pollution Probe, Northwatch), the independent power generation industry represented by IPPSO and by individual intervenors from that industry (Toromont, EnergyLink), and the natural gas industry represented by ONGA. FOCA, OFA, TransCanada Energy and the Chiefs also supported net load billing.

Board Findings

3.2.15 The Board notes that there is general agreement that net load billing for network service has been the practice under the bundled electricity regime. Customers opting for embedded generation did not pay for transmission services they did not receive. This is also the normal commercial practice in other industries.

3.2.16 There is also general agreement by the proponents of gross load billing that, in the long run, there will be a return to the normal practice, after the issue of overcapacity and transmission sunk costs is no longer a concern. The key issue therefore is an assessment of the considerations that may dictate or warrant departure from net load billing. The Board therefore will address the key arguments in favour of gross load billing in general as well as the specifics of the OHNC proposal.

3.2.17 The main objection to network net load billing is the "cost shifting" that would occur when loads leave the transmission system as a result of installing new embedded generation. As noted earlier, according to the evidence net load billing for network service and gross load billing for connection service, based on a forecast by Agra Monenco of 2,550 MW of new embedded generation by year 2008, results in a 24.6% decrease for the 20 largest "highly embedding" direct industrial customers and an increase of 7% for the "non-embedding" LDCs. The weighted average transmission rate may be about 7% higher by 2008 under net load billing than under gross load billing. As noted earlier, the OHNC proposal would somewhat mitigate the above impacts.

3.2.18 However, according to the evidence, transmission costs comprise only about 15% of the total delivered electricity cost in the Province. The electricity commodity component, about two-thirds, is the major component. According to a forecast provided by OHNC, about half of the new embedded generation in the next several years, forecast to develop under net load billing, will be cogeneration directly connected to the host load; the other half will be embedded new merchant generation and reconnected generation. There was no evidence or assessment of the commodity price impact that may occur with the introduction of new generation in general. It was noted that any such quantification would be difficult given the lack of history in this regard and isolating this result from the impact of the reduction in market power of OPG pursuant to the Market Power Mitigation Agreement. It was however generally accepted, even by certain parties advocating gross load billing, that commodity prices ought to decline if more supply was available from non-OPG sources.

3.2.19 From the above, the Board reaches the following conclusions. First, the 1.5% difference in the average transmission rate between full gross load billing and OHNC's proposal is not significant. Second, while there would be some greater rate impact for "non-embedding" LDCs under net load billing for network, the effect on customer bills ought to be reduced as a result of competitive merchant generation coming on stream. Third, any remaining impact on overall transmission customer bills because of net load billing would be gradual.

3.2.20 Having reached these conclusions regarding cost shifting, the Board will now assess the other considerations and implications of the net versus gross load billing debate.

3.2.21 Key aspects of the debate are the positions taken on the responsibility for sunk costs and the user pay principle. The diametrically opposed interpretation of the user pay principle in this case proved of little value to the Board in resolving the issue. To the proponents of gross load billing, the user pay principle means that the sunk costs of the transmission system must continue to be shared by those for whom the transmission capacity was built. For the proponents of net load billing, the user pay principle dictates that a customer should only pay for the services that the customer uses.

3.2.22 In the Board's view, if the issue were to be resolved solely on the user pay principle, the conclusion can only be that customers should not have to pay for services not being used. It appears to the Board that the issue advanced by the proponents of gross load billing is that of responsibility for transmission sunk costs, not the user pay principle.

3.2.23 Unlike connection facilities, network facilities were built for a mix of customers. The mix is not static; it changes continually. The customers who will use the system at market opening will not necessarily be the same customers for whom the transmission network was built. Transmission lines built for one purpose may be adapted to another depending on changing service needs. For example, many of the 115 kV lines in Southern Ontario that are now allocated to the line connection pool were originally built as network facilities.

3.2.24 The distinction between connection facilities and network facilities is also evident in the financial treatment of each. It is normal practice to require financial contributions from customers requiring dedicated connection facilities or causing the expansion of certain connection facilities. A financial contribution is not normally required from any single customer for expanding the transmission network system.

3.2.25 The ratemaking principle of "used and/or useful" also informs. This regulatory principle deals with utility assets that may not be currently used but may be considered useful in the future. Not used or under-utilized network assets which result from installing embedded generation may in fact be useful in the future. Over time as transmission capacity needs grow, and as some loads decline they make capacity available for other loads to grow or be added without the need for expansion to the network transmission system. This has taken place throughout the build-up of Ontario's transmission system. There is no reason to suggest that this will not continue. What appears to be the main issue is whether the present over-capacity of the network system will persist longer under the new market structure if new embedded generation is developed. This may or may not be the case. In any event, this does not make the "useful" principle less valid or inoperative. Certainly, there is no evidence to suggest that embedded generation will pose an unmanageable threat to the financial integrity of the existing transmission system. Moreover, while the Board recognizes that there may be financial impacts to specific customers, the public interest dictates that the objectives of open access should not be frustrated by the current demand-capacity imbalance in the transmission system.

3.2.26 The application of gross load billing on a going forward basis, whether full or partial, leads to the need to make a number of other regulatory assessments and decisions. The OHNC proposal creates a distinction between reductions in transmission service taken because of embedded generation and other factors. The net level of load on the transmission system can be reduced because of plant closures, reduced operations, increased energy efficiency, or substitution of other fuels. These other sources of load reduction are not subject to the penalty of network gross load billing as is proposed for embedded generation.

3.2.27 Gross load billing for network services would necessitate highly complex rules and regulations that would have nothing to do with the level of transmission services taken or the cost of providing transmission service. Among other things, these rules would place some industrial customers on whom gross load billing would be imposed at an unfair disadvantage compared to their competitors who, by historical circumstance, enjoy net load billing.

3.2.28 OHNC's proposal to apply gross load billing with a 50% access fee for efficient new embedded generation, leads to the need to decide what can be considered "efficient". One criticism of the OHNC proposal is that in assessing "efficient" generation, OHNC would apply its own judgement. That criticism would not abate if the Board were to be the ultimate arbitrator since it would draw the Board into an area of questionable jurisdiction.

3.2.29 The Board observes that the above cited problems of gross load billing would be avoided by the immediate adoption of net load billing for network services.

3.2.30 In the Board's view, OHNC's proposal to eventually tailor requirements of specific customers installing embedded generation is problematic for a number of reasons. Customer-specific contractual arrangements would likely require changes in the regulatory process, commercial arrangements, changes to the Transmission System Code, and detailed market design processes. Also, the negotiated arrangements with specific customers will likely lead to issues regarding transparency, equity and fairness. Moreover, the intent to move to such a regime would create uncertainty from now until it is implemented. In the Board's view, this is not a welcoming prospect as large power users and providers must begin now to make important decisions on embedded generation.

3.2.31 While the Board is of the view that transmission rates should not necessarily be designed with environmental improvement as a dominant consideration, environmental perspectives must also be factored in. Pollution Probe estimated the reduction in pollutants from substituting gas-fired generation for 1950 MW of coal generation and argued that such reductions should be considered significant.

3.2.32 It was argued by certain proponents of gross load billing for network services that net load billing does not recognize the benefits of being attached to the transmission system. The benefits mentioned included power quality support, access to replacement energy and opportunities to sell excess electricity into the market. However, the Board accepts the argument by certain parties that it may not be reasonable to suggest that the charge that will result from gross billing, whether at 100% or 50%, is justified. With respect to the issue of whether there should be any kind of additional charge under net load billing, the Board accepts that power quality support goes both ways; it is both received and given by embedded generation. Moreover, as noted by certain parties, OPG is not charged for these benefits. The Board finds that no other network charges in addition to the demand charges approved by the Board in this Decision should be imposed for embedded generation.

3.2.33 On balance then, the Board finds that net load billing shall apply to network transmission service. Current users of the transmission system will continue to pay for the level of transmission service they use. In the Board's view, given the circumstances presented, net load billing for network service is a fairer, more practical and simpler system to apply. It removes the arbitrariness inherent in gross load billing; it removes the uncertainty over future transmission pricing for embedded generation; and, it does not frustrate the objectives inherent in open access, particularly the opening up of the energy market to alternative generation. The Board recognizes that there will be some cost impacts as a result of its findings but they ought to be mitigated by anticipated developments in new generation.

3.2.34 Furthermore, future transmission rates will depend on a number of other factors. One such factor is the revenue requirement of OHNC. The testimony in this proceeding about potential impacts on transmission rates reflected an unchanged revenue requirement for the period under consideration. The Board notes that the ultimate transmission rates will reflect regulatory developments, such as Performance Based Regulation, which ought to contain future rate increases or even result in decreases in transmission rates.

Line and Transformation Connection Pools

3.2.35 OHNC proposed that the Line and Transformation Connection Pool charges should be based on gross load billing.

3.2.36 Many parties noted that these facilities were built for the dedicated use of one, or a group of load customers, and therefore reductions in load due to installation of embedded generation should not shift costs to other customers served from the pools.

3.2.37 Some of the proponents of net load billing distinguished their support for net load billing for network services from the connection transmission service and suggested that gross load billing for the latter would be appropriate. Other proponents of net load billing did not distinguish the different parts of the transmission system in their arguments.

Board Findings

3.2.38 The distinction between transmission network facilities which serve all customers and transmission connection facilities is that the latter were constructed as a result of specific customers requiring these specific facilities. The rate making principle that informs here is that of "used and/or useful". If transmission connection facilities are neither used nor useful as a result of installation of embedded generation, in that they will in all probability not be used in the foreseeable future, they are stranded. The stranded costs must either be borne by the shareholder, by all customers, or by the specific load customer that chose to install embedded generation. A case could be made that those costs should be borne by the shareholder, if the loss of load was a result of normal business risks in a normal operating industry. However, this is not the case here. The potential loss of load is a direct result of a substantial industry restructuring as a result of government legislation. Also it would not be reasonable to recover such costs from other existing customers who would not benefit from the existence of these assets. Accordingly, the Board determines that stranded connection costs should be borne by the load customers that cause them by installing new embedded generation.

3.2.39 The Board therefore finds that for load customers with new embedded generation the charges for Line and Transformation Connection service should be based on gross load billing.

Exemptions From Gross Load Billing

3.2.40 For reasons of administrative simplicity and cost efficiency, OHNC proposed that new embedded generation under 1 MW serving existing load should be exempt from gross load billing and be billed on a net load basis. It was OHNC's view that the minimal cost shifting resulting from such small scale generation would not justify the costs of metering and billing.

Board Findings

3.2.41 Given the Board's findings above that net load billing shall apply for network transmission service, the issue remains as to the appropriateness of the requested exemption for connection facilities and the specific threshold for new embedded generation.

3.2.42 The Board notes that the testimony by witnesses for IPPSO and EnergyLink as well as parties' arguments did not adequately distinguish whether the exemption ought to apply regardless of the Board's findings on the net versus gross load billing issue. Intervenor positions on the threshold exemption generally followed the same arguments regarding net versus gross load billing. Proponents of gross load billing supported the OHNC proposal. Proponents of net load billing argued for an exemption threshold as high as 20 MW, with the exception of Northwatch who supported net load billing but accepted the 1 MW threshold. No party argued for no exemption at all. The starting point was the OHNC proposal of 1 MW.

3.2.43 Therefore it is not clear as to the extent to which some of the specific recommendations advanced by certain parties can hold in light of the Board's earlier findings, such as OPG's suggestion that the exemption be re-examined within five years. Also the Board is not clear as to the extent to which certain intervenor proposals for the 20 MW threshold were made in the context of OHNC's position on gross load billing for network charges, which the Board has not accepted.

3.2.44 The only remaining issue, in the Board's view, is that of administrative costs and simplicity. Gross load billing for smaller loads would require the installation of metering and the incorporation of these loads in the IMO's billing and settlement process, thus creating costs and complexities for both the generator and the system as a whole which would likely outweigh any benefits from billing for such facilities. The Board also notes from the information provided that generators of less than 1 MW are also exempt from IMO dispatch and scheduling requirements. The Board therefore accepts OHNC's proposal.

3.3 EXISTING EMBEDDED GENERATION

3.3.1 Existing embedded generation is defined as embedded generation for which required approvals were obtained before October 30, 1998, when the *Energy Competition Act 1998* came into being. All other embedded generation is referred to as new embedded generation. Historically, customers with existing embedded generation have been billed for both network and line/transformation on a net load basis.

3.3.2 Having assessed a number of options, OHNC proposed that load which is supplied by the existing embedded generation should continue to be billed on a net load billing basis, that is the charge determinant for Network, Line Connection, and Transformation Connection services should not include that portion of the load which is supplied by the existing embedded generation.

Board Findings

3.3.3 The Board notes that no party opposed OHNC's proposal. The Board agrees with OHNC that load supplied by the existing embedded generation should continue to be billed on a net load basis.

3.4 CHARGE DETERMINANTS AND RELATED MATTERS

3.4.1 In Chapter 2 the Board approved the establishment of the three cost pools (Network, Line Connection, Transformation Connection) as proposed by OHNC. On the basis of the defined pools, and reflecting the Board's findings on net versus gross load billing, the transmission charges (to be applied monthly on a per delivery point basis) for load customers after open access will comprise one or more of the following components:

- Network Pool charges that will apply to all transmission customers. According to OHNC's proposals, the revenue requirement to be recovered from such charges is $675 million or 58% of the total revenue requirement.

- Line Connection Pool charges that will apply to customers utilizing the regulated transmission line assets owned by OHNC. According to OHNC's proposals, the revenue requirement to be recovered from such charges is $189 million or 16% of the total.

- Transformation Connection Pool charges that will apply to customers utilizing the regulated transformation assets owned by OHNC. According to OHNC's proposals, the revenue requirement to be recovered from such charges is $299 million or 26% of the total.

3.4.2 If a customer has fully contributed to building of a transformation station or to building of their line connection to the network station, the costs associated with those assets are not assigned to the respective connection pools and the customer will not pay charges related to these services.

3.4.3 OHNC's proposals on charge determinants incorporate its proposals on certain related matters pertaining to the choice of a monthly billing cycle, billing on the basis of per delivery point rather than on the basis of aggregate load from more than one delivery point, and the exclusion of fixed or minimum charges. These matters are addressed before the discussion of the main issue of the appropriate charge determinant for network and line/transformation connection.

Billing Cycle

3.4.4 Billing cycle defines the frequency of billing and payment for transmission charges. OHNC proposed a monthly billing cycle.

Board Findings

3.4.5 The Board notes that no party took issue with OHNC's proposal. The Board accepts the monthly billing cycle as appropriate. Monthly billing is commonly used and consistent with the billing frequency proposed for the IMO, who is responsible for the billing and settlement for transmission charges.

Charges Per Delivery Point

3.4.6 Transmission services may be charged on an aggregate per customer basis or on a per delivery point basis. On an aggregate per customer basis, the transmission charges would be calculated on the customer's aggregate demand for all delivery points for a given time interval. If assessed on a per delivery point basis, the customer's charges would be calculated separately for each delivery point. OHNC proposed that transmission charges be calculated on a per delivery point basis.

3.4.7 Toronto Hydro suggested that OHNC be directed to explore the impacts of allowing transmission customers served by more than one delivery point to aggregate the total load for billing purposes and to report on this matter in OHNC's next rates case.

3.4.8 MEA suggested that in circumstances where an LDC is served from more than one delivery point and due to maintenance at one delivery point demand increases at another delivery point, there ought to be a provision not to charge for the "maintenance peak". In MEA's view this can be accomplished through appropriate notification for pre-approval of shifts among delivery points.

Board Findings

3.4.9 In the Board's view, the alternative of allowing customers to aggregate demand from delivery points for billing purposes would provide an unfair advantage to those customers with diversity of demand from geographically different delivery points at the expense of other customers. The Board is also of the view that allowance for shifting as suggested by MEA is cumbersome, inconsistent with the user-pay or fairness principle and impractical. The Board therefore accepts OHNC's proposal for transmission charges to be calculated on a per delivery point basis.

Fixed and/or Minimum Charges

3.4.10 Under a fixed charge provision, a customer at each delivery point would be responsible for certain monthly charge even if the customer does not register a meter reading during the month. Under a minimum charge provision, the charge determinant for each customer at each delivery point would be no lower than a predetermined amount or "floor". OHNC proposed that there should not be a fixed or a minimum charge provision.

Board Findings

3.4.11 The Board notes that, given the large size range among transmission customers, the imposition of a fixed and/or minimum charge is not desirable or meaningful. At any level, such charges would be hefty for smaller customers and inconsequential for larger customers. The Board therefore accepts OHNC's proposal that there should not be any fixed or minimum charges.

Network Pool Charge Determinants

3.4.12 The term "charge determinants" refers to the volumetric or demand measure that may be used for assessing transmission service charges. OHNC identified three basic charge determinant options - fixed or minimum charges per delivery point, MW peak demand, and MWh energy used. The peak demand can be calculated as either coincident or non-coincident. Coincident peak demand is the demand of a transmission customer at the time when the whole transmission system demand is at its peak. Non-coincident peak demand is the peak demand of a transmission customer irrespective of the time when it occurs.

3.4.13 Having assessed a number of options, OHNC proposed that the monthly charge determinant for the network pool should be the higher of the coincident peak demand or 85% of the customer peak demand, at each delivery point, during the peak period of 7:00 am to 7:00 pm on weekdays of the month that are not holidays.

Positions of the Parties

3.4.14 AMPCO led evidence supporting a network charge determinant based on either a one-hour monthly coincident peak or the average 50-hour monthly coincident peak. The latter would, in AMPCO's view, mitigate the possibility of gaming and reduce some of the uncertainties that arise with a one-hour coincident peak. AMPCO noted that these choices fully recognize the diversity of all customers on an equitable basis and allow customers who can schedule their use of the system at times of lower system usage to continue to do so at low cost.

3.4.15 The OHNC proposal reflected a compromise between the extreme positions in support of coincident and non-coincident demand peak. Some intervenors who may have preferred another alternative were prepared to support the OHNC proposal as a compromise.

3.4.16 OHNC's proposal was supported by Northwatch, Sunoco, ECMI, OPG, PWU, and Toronto Hydro. AMPCO's proposal was supported by IPPSO, and TransCanada Energy. A network charge determinant based solely on non-coincident peak demand was suggested by MEA, FOCA, CAC, VECC and CDU. A pure coincident peak charge determinant was advocated by GEC and Toromont. The Chiefs advocated a consumption-based, time-related network charge determinant. In some cases, the support for a party's position was conditional upon Board acceptance of the party's position on other cost allocation and rate design issues, particularly the definition of the line connection pool and the net versus gross load billing debate.

3.4.17 Proponents of a network coincident peak demand charge determinant argued that, from a cost causality perspective, this option is superior to the non-coincident peak demand option. While it was recognized by some of these proponents that the coincident peak option is more open to free ridership, that is, customers can avoid paying to the extent they are able to schedule their use of the system to avoid certain hours. This problem, in their view, is not large enough to negate the causality consideration. The coincident peak demand option, it was argued, would recognize the real diversity benefits created by industrial users. It was suggested that charge determinants should foster efficient long-run outcomes and charges based on coincident peak demand would emit the appropriate price signals, despite the existence of overcapacity at the present time.

3.4.18 Supporters of AMPCO's proposal noted that the proposed 50-hour feature addresses the concern that the use of a single one-hour demand peak does not always capture peak effects across the entire network system and that it may be susceptible to gaming. It was suggested that any remaining concerns about free ridership can be addressed by way of a minimum bill. Regarding the criticism that the 50-hour provision introduces complexities since it is based on identifying, after the fact, the precise charge determinants, it was pointed out that any coincident peak determinant, such as OHNC's proposal, uses a retrospective calculation. It was also stated that the 50-hour feature of the AMPCO proposal does not require additional metering or additional meter reading.

3.4.19 Proponents of a non-coincident peak charge determinant argued that the capacity of various network transmission assets in Ontario are not determined by the system peak. Rather, these assets are generally designed to meet local, non-coincident peak demand and when there is not a significant or distinct peak, as is the case in Ontario, coincident demand billing is inappropriate. It was also argued that the use of the network transmission system is a result of the traffic on the system caused by the dispatch of generation to meet load. Locational marginal pricing of energy would provide indications of which parts of the system are congested and which are not and, therefore, which parts of the system require expansion. There is no relationship, it was argued, between the choice of charge determinant and potential network requirements over the long-term. Even if actual usage of the transmission system was signalled through the charge determinant, the network transmission system in Ontario is not at full capacity and there are no short-term savings by creating spare capacity as a result of giving customers an incentive to avoid using the system at the time of system peak.

3.4.20 Proponents of a non-coincident peak charge determinant for network service held that acceptance of coincident demand peak as a charge determinant would allow unacceptable free ridership. They noted that fairness requires that customers with similar peak demands should pay similar charges, because they place similar demands on the system. It was also noted that coincident demand peak is inefficient in terms of cost recovery since revenue can fluctuate because of gaming. Therefore, if a coincident network charge determinant is used, there ought to be a minimum charge for those customers who game the system so that they can also contribute toward the fixed costs.

Board Findings

3.4.21 The Board notes that locational transmission pricing, where charges would vary according to location, was not an issue for this proceeding. Therefore the Board's considerations are only with respect to uniform (postage stamp) charges using a pool-based methodology.

3.4.22 The Board notes that the Chiefs were the only party suggesting a charge determinant based largely on energy consumption rather than peak demand. The Chiefs argued that charge determinants based on consumption are less complex, prevent gaming, and provide an incentive for customers not to use the system at peak hours. These characteristics in the Board's view are not unique to consumption-related charge determinants. They can equally apply to certain demand-related charge determinant options, such as non-coincident peak demand.

3.4.23 Having assessed the merits of various charge determinants for network service, the Board concludes that, on balance, charge determinants based on peak demand have stronger support in regulatory principles for network transmission pricing where costs are largely fixed, as is the case with the OHNC transmission system. The issue then is which demand related charge determinants, or which combination, may be more appropriate for Ontario's network transmission system.

3.4.24 Cost causality was a major theme in parties' positions. The Board considers that, for the commonly shared network transmission system, once the regulated assets are in place and recovery of historic sunk costs is the issue, the application of the principle of cost causality is not unequivocal. The particular circumstances of Ontario's network transmission system and other considerations, such as revenue requirement, efficiency and fairness, must also be weighed.

3.4.25 Much discussion took place about the revenue requirement impacts between the various charge determinant options. For example, the revenue assignment differences arising from OHNC's proposal for the higher of the customer's hourly coincident peak demand during the month, and 85% of the customer's peak demand in any hour during the peak period between 7 AM to 7 PM on weekdays and the proposal for a charge determinant based on a one-hour coincident demand peak or the average 50-hours system peak advocated by AMPCO are, in the Board's view, *de minimus.* The revenue requirement associated with the Direct industrial customers is $120 million under the OHNC proposal compared to $119 million for the one-hour coincident demand peak proposal and $120 million for the average 50-hour coincident demand peak proposal. For the LDCs and for OHNC Distribution, the differences in revenue requirement among the options are of similar insignificance. The Board therefore must look at other considerations that may be of greater significance.

3.4.26 When comparing AMPCO's one-hour coincident peak option with the average 50-hour coincident peak option, while the advantages appear to be similar, the result of the one-hour coincident peak option is a higher potential for free ridership and gaming as customers may likely attempt to escape the coincident peak hour.

3.4.27 A rate design aimed at customer demand reduction during the system's coincident peak hours would meet the test of economic efficiency, but only if the network transmission system is generally capacity-constrained. This is not the case for the OHNC network transmission system either today or in the foreseeable future. The issue therefore of constructing a rate design which would avoid capacity expansion is of secondary importance. The fairness issue of recovering the sunk transmission system costs therefore becomes important. Exclusive reliance on the coincident peak method where some customers may be able to withhold demand in that period while others do not have such opportunity will result, in the Board's view, in unfairness.

3.4.28 Under the OHNC proposal (the higher of the customer's demand coincident with the system peak demand and 85% of the non-coincident peak demand), concerns about free ridership and gaming are somewhat reduced. The choice of 85%, while somewhat arbitrary, does reflect the fact that the average monthly system coincidence factor (the ratio of coincident peak demand divided by non-coincident peak demand) is of the order of 85%.

3.4.29 Given all of the above, the Board accepts OHNC's proposal regarding charge determinants for recovering the costs associated with the network pool. The charge determinant for network service shall be the higher of the hourly coincident peak demand during the month and 85% of the customer's peak demand in any one hour during the peak period between 7 AM to 7 PM on weekdays that are not statutory holidays.

3.4.30 In making this finding the Board has considered the option advocated by certain parties that, in the event that the Board does not find in favour of one of the variants of coincident peak charge determinant, the Board should accept a transmission rate design which incorporates a back-up rate to apply to customers with embedded generation. The Board has concluded that the Board-approved rate design ameliorates the impact of forced outages and provides flexibility for planned outages of embedded generation. Therefore, no transmission back-up rate is warranted at this time.

Connection Pools Charge Determinants

3.4.31 OHNC proposed that the monthly charge determinants for the line and transformation connection pools should be the customer's monthly non-coincident peak demand, by delivery point. The main rationale provided was that, since the capacity of these facilities is not related to system-wide demand, but rather local demand, it would be inappropriate to allocate these costs on any basis other than non-coincident peak demand.

3.4.32 This rationale received broad acceptance from those intervenors who supported the OHNC proposal, those who argued for a non-coincident peak demand for network service and those who supported coincident peak for the network transmission and made the distinction between network and connection, with the exception of Toromont who advocated a coincident type of billing for connection services. Certain parties, particularly AMPCO and IPPSO, suggested certain refinements relating to the allocation of costs to customers using the same delivery point.

Board Findings

3.4.33 The Board notes the broad consensus that a charge determinant for connection services based on a customer's non-coincident peak demand is appropriate. Unlike the network transmission facilities, the line and transformation connection facilities are specifically dedicated to serving a single customer or a relatively small group of customers and therefore are of no obvious use to the remaining customers of the transmission system. The costs of these dedicated assets therefore must be recovered from these customers. The Board notes that certain parties proposed certain refinements or variations to the gross load billing for connection service. In the Board's view, any refinements to gross load billing for connection services can only be considered after experience has been gained.

3.4.34 The Board accepts OHNC's proposal that the charge determinant for line and transformation connection services be based on the customer's monthly non-coincident peak demand at each delivery point.

3.5 TREATMENT OF NEW LOAD CONNECTION INVESTMENT

3.5.1 Over time, new line and transformation connection investments will be required as new load customers are added to the transmission system or existing load customers require upgrades. Having assessed various options, OHNC proposed that, in the short term, load customers requiring new connection facilities can choose either to self-provide those facilities, or choose to have these facilities constructed by OHNC so that the costs of such construction are included in the respective regulated pool. A financial contribution by the customer may be required in order to hold the pool(s) harmless. These provisions represent a continuation of historical and current practice. OHNC also proposed that the costs for new connection facilities approved by the Board in the Transitional Rate Order for 2000 be included in the connection pools.

3.5.2 For the longer term, as the market for customer provision of connection facility construction matures, OHNC proposed that load customers take full responsibility for new connection facilities.

3.5.3 OHNC pointed out that a Board decision on this issue would not directly impact on the proposed transmission cost allocation and rate design, but would only affect the choices available to customers.

Positions of the Parties

3.5.4 The OHNC proposals were supported by PWU, CAC, Five Nations Energy, and GEC. CAC suggested that the Transmission System Code, under development, should consider the use of standardized parameters in the determination of customer contribution guidelines. Five Nations Energy urged the implementation of OHNC's long-term proposal for customer provision as soon as it becomes evident that competition exists for the provision of new connection facilities.

3.5.5 MEA and CDU supported OHNC's proposals but submitted that some allowance should be made for new facilities which have been deferred due to LDC participation in Local Integrated Resource Planning ("LIRP") initiatives, a position advanced by Collingwood Hydro. Specifically, Collingwood had entered into an LIRP initiative with former Ontario Hydro in 1990 in order to defer an $80 million investment in new facilities. The LIRP was successful but Collingwood Hydro anticipates that new facilities will be needed in the future, which may result, under OHNC's proposals, in Collingwood Hydro being required to make a financial contribution. Collingwood Hydro suggested that LIRP initiatives should be treated differently than other new line or transformation projects; that is, OHNC should be responsible for the full future cost of the deferred facilities.

3.5.6 ECMI supported the OHNC short-term position, but rejected the long-term position on the basis that it will likely cause rate and cost lumpiness to LDCs, resulting in rate instability for their customers. ECMI suggested that these concerns be addressed through financial contribution policies.

3.5.7 IPPSO supported the user pay principle reflected in the OHNC's proposal, but submitted that OHNC's long-term proposal should be implemented in the near future. It suggested that OHNC report in its next rate case on the choices (self-installation vs. OHNC installation) made by customers.

3.5.8 PWU noted that there is no evidence to conclude that sufficient competition exists such that the Board should prohibit OHNC from undertaking this activity, and suggested that it may appropriate to revisit this issue in the future, perhaps in the context of a future revision of the Transmission System Code.

3.5.9 The Chiefs criticized the OHNC proposal in that it does not take into account the customer's distance from the network. Therefore, charges for connection facilities should be at "postage stamp" rates and no financial contribution would be required. Alternatively, First Nations should be exempt from new connection investment charges.

3.5.10 AMPCO stated that the rules to manage customer ownership of connections do not need to be settled prior to market opening. The Board should establish a schedule for a stakeholder consultation process and perhaps a technical conference in which the Board, OHNC, and the IMO should play equally significant roles. The results of this process could be incorporated into the Transmission System Code now under development.

3.5.11 ECAO argued that section 50(4) of the *Electricity Act* does not permit OHNC to engage in the provision of new load connection investments, which do not constitute "transmitting or distributing electricity"; only non-regulated affiliates of OHNC should be permitted to compete for and provide these investments.

3.5.12 In its Reply argument, OHNC noted its expectation that many of the issues raised by intervenors would be addressed in other processes under development, including the Transmission System Code and that there is no need for the Board to establish an additional process.

3.5.13 With respect to ECAO's interpretation of OHNC's role under the *Electricity Act*, OHNC noted that the *Electricity Act* is not clear on the activities that may be included in the definitions of the words "transmit" and "distribute". OHNC also noted the wide preference by intervenors that the pooling option remain available in the short term. It also noted that ECAO has not submitted any evidence to indicate that there is a load connection market at the present time.

3.5.14 OHNC disagreed with the arguments by Collingwood Hydro and the Chiefs on the grounds that they constitute requests for special treatment.

Board Findings

3.5.15 The Board recognizes that the *Electricity Act* does not provide definitive answers as to what constitute transmission or distribution activities. In the case of transmitters, in the absence of any formal review or direction at this time, the Board has been guided by the practical considerations of the issue. In that regard, the Board is mindful of the need to assist in the transition of the electricity market to its new structure in an orderly way.

3.5.16 In the Board's view, it would be premature to consider directing OHNC to exit the connection construction market until the Board has evidence before it on the competitiveness of that market. The Board therefore accepts OHNC's transitional proposal as reasonable. The Board notes that, even under OHNC's dual function definition of the network assets, some load customers will have the option to either self-provide connection facilities or to request OHNC to provide these facilities. The

Board also notes OHNC's desire to eventually eliminate its role in the provision of new connection facilities.

3.5.17 The timing of eliminating the OHNC-provided option however very much depends on how quickly the competitive market for construction of these facilities develops. This in turn depends on three things. First, the OHNC-provided option must not be subsidized in any way. In this regard, while the objective of holding the respective pools harmless is laudable, it should not be the only objective. The other objectives must be to ensure that choice of a costing policy will not discourage the development of the competitive market. If, for example, the hold harmless objective leads to a financial contribution that, in total, represents a cost to the load customer well below market alternatives, the connection facilities market may never develop as envisaged by OHNC. It is therefore important that OHNC adopt a costing policy for connections that represents fully allocated costing.

3.5.18 The Board expects that the guidelines currently being developed as part of the draft Transmission System Code will reflect the Board's expectations in these areas. Once the guidelines regarding load connection investments are prepared in a form consistent with the Transmission System Code, the Board expects OHNC to make them available to load customers on request. The guidelines are expected to set out the methodology for pricing and customer contributions to new load connection facilities under the pool(s). This will serve to allow customers and contractors to compare the case-specific alternatives of self-provision with pool provision.

3.5.19 Second, there should be a target date established by OHNC for the elimination of the OHNC-provided option. This will provide more certainty toward the further development of alternative providers. Third, OHNC should not seek to monopolize the connection market. Rather, it should take steps to encourage competition. In this regard, the Board notes that the resolution of the dual function definition of network lines is critical to the full development of the competitive market for line connection facilities. The Board expects OHNC to report on these matters at its next cost allocation/rate design proceeding.

3.5.20 The Board has considered the specific requests made by Collingwood Hydro and the Chiefs. Consistent with the Board's findings throughout this Decision, the Board does not accept requests for special treatment such as that requested by Collingwood Hydro, which will cause a burden on the remaining customers in the pool.

3.5.21 The Board was asked by OHNC to specifically confirm OHNC's proposal that the costs for new connection facilities approved by the Board in the Transitional Rate Order for 2000 be included the corresponding connection pools. The Board confirms OHNC's proposal.

3.6 NETWORK AND CONNECTION COSTS FOR GENERATORS

3.6.1 The consultation process undertaken by OHNC resulted in general agreement among stakeholders that existing and new generators should pay for any new connection facilities or upgrades, but they should not be required to pay network charges as these would ultimately be borne by the load customers in any event through the generator's pricing of the commodity. There was however, a divergence of views as to whether existing generators should have to pay charges with respect to existing connection facilities, which are in some cases shared with LDCs or Direct industrial customers.

3.6.2 The stakeholdering process revealed that those stakeholders who felt existing generators should not pay for existing connection costs suggested the costs should be included in the network pool. They pointed out that if this is not the case, the Market Power Mitigation Agreement would need to be revisited since it was based on the recommendations of the Market Design Committee that none of the existing connection costs should be borne by the existing generators. Other stakeholders felt that any proposals that would appear to give an advantage to Ontario's existing generators compared to other jurisdictions, such as those in the United States, could be detrimental in the context of the North American Free Trade Agreement (NAFTA) and that this might lead to countervailing measures. Those stakeholders who felt that existing generators should pay for existing connection costs indicated that this preference was based on the principle of fairness to new generators.

3.6.3 In its prefiled evidence, OHNC noted that assigning existing generators a share of connection costs is not the normal practice in surrounding jurisdictions and would thus place OPG at a competitive disadvantage which would be contrary to the intent of the Market Power Mitigation Agreement. OHNC also noted that its assignment of such costs to generators might potentially have an impact on the structure of the Competition Transition Charge and the capitalization of OPG; in both cases there was an implicit assumption that OPG would not be assigned any existing connection costs. In addition, existing Non-Utility Generation (NUG) contracts held by OPG would need to be unbundled to break out a cost for transmission.

3.6.4 According to OHNC, the generators' share is $77 million of the total line connection asset pool of $797 million and $13 million of the total transformation asset pool of $1,128 million. In terms of annual revenue requirement, the amounts are $18.1 million and $3.2 million respectively. If the generators' share of revenue requirement of the two pools were to be absorbed with the network pool revenue requirement, the additional $21.3 million revenue requirement represents an increase of 3.3%.

3.6.5 In its prefiled evidence, having assessed the various options, OHNC concluded that existing generators should not be assigned the existing transmission connection costs and that these costs should be combined with the network costs and charged to all load customers. However, OHNC stated that, given the concerns regarding potential trade implications, this issue should be studied at a later date.

3.6.6 By agreement of all parties, the issue of the process and timing of a review of this issue was left for argument only.

Positions of the Parties

3.6.7 In its Argument-in-Chief, OHNC suggested that review of this issue by the Board should not take place until after the next transmission revenue requirement application. OHNC's preference is for a <u>written</u> hearing but the Company acknowledged that the scope of this "special type of review" may make the written format impractical.

3.6.8 IPPSO, AMPCO, TransAlta, the Chiefs, TransCanada Energy, OFA, and Toronto Hydro submitted that existing generators should be responsible for the costs associated with the connection facilities used to tie into the network transmission system on the principle that not doing so creates an unfair advantage to OPG over potential future generators. IPPSO and AMPCO proposed that OHNC should conduct a cost allocation study to identify and value the connection assets relating to existing generators and apply to the Board no later than the first quarter of 2001 for approval of the creation of a distinct pool for the existing generation connection assets. In the interim, TransAlta suggested that a reasonable portion of the revenue requirement be recovered from existing generators through a “placeholder” charge. OFA suggested an interim charge of $1 per MW per kilometer toward the recovery of maintenance costs and to ensure that the value of these assets “are not wholly alienated or captured by the wrong party if generators are sold”. Northwatch also suggested that a charge be levied immediately.

3.6.9 GEC submitted that the competitive situation in Ontario will be impacted by the resolution of this issue and an early decision will help bring certainty to the market. The Board should indicate its intent to review this matter so that potential buyers of existing generating assets will be alerted to the regulatory issues outstanding.

3.6.10 OPG submitted that OHNC’s allocation of the existing generator connection assets to the network pool should be adopted as it is consistent with Ontario Government’s restructuring decisions, the MDC recommendations on this issue, and the treatment of similar assets by the Federal Energy Regulatory Commission (FERC) in the United States. OPG argued that no further process is warranted. It further submitted that, should the Board have any doubts about the Government’s intentions, it can simply express these doubts in its Decision and invite the Government to direct further review of this matter.

3.6.11 Energy Probe urged the Board to reject the imposition of any measures that would seek to revisit the financial restructuring of Ontario Hydro into its successor firms and the MDC’s reasons for rejecting the imposition of any connection charges on existing generators. Similarly, MEA and CDU recommended that generators should not be charged for existing transmission connections, and suggested that no further review of this issue is needed.

3.6.12 In its Reply argument, OHNC reiterated that this is a "second generation" issue, to be dealt with after the next transmission rates case and under a separate proceeding.

Board Findings

3.6.13 The Board notes that OHNC's proposal that all existing and new generators be required to pay for investment in new connection facilities or upgrades to existing facilities has not been challenged, except from the Chiefs who argued that all charges associated with First Nations' merchant generation should be included as network charges and paid by all load customers. The Board agrees with OHNC that this would constitute special treatment. For reasons stated throughout this Decision, the Board has not accepted requests for special treatment. The Board accepts the OHNC proposal as reasonable. The Board also accepts as reasonable OHNC's proposal that existing and new generators should not be required to pay network charges since these would ultimately be borne by the load customers in any event through the generators pricing of the commodity.

3.6.14 What is being contested is the responsibility of existing generators for the costs associated with the existing connection facilities. The Board in effect is being asked by certain parties, advocating that existing generators pay for existing connections, to either reverse or review at a later time decisions already taken by the Ontario Government. The issue then is one of both substance and process.

3.6.15 The Board observes that certain parties argued the merits of the issue, which clearly went beyond the agreed upon purpose of the issue remaining on the Board-approved issues list. In any event, the Board does not have adequate information before it to comment on the substance of this issue. Even if it had adequate information, and saw some merit in the position that existing generation should pay for existing connections, this matter cannot be concluded under a Board-driven process. The broad policy implications reflected in the Government-driven electricity market restructuring, including the asset allocation and financial structure and arrangements of the Ontario Hydro successor companies, necessitate a broad review, if one is necessary, that is best led by the Government itself. The Board has not formed a view whether such review is necessary and, accordingly, makes no recommendations in that regard.

3.7 REQUESTS FOR SPECIAL TREATMENT

3.7.1 This section deals with the requests for special treatment for First Nations communities and for existing Ontario Hydro contracts.

First Nations

3.7.2 OHNC's Application makes no specific rate proposals respecting First Nations communities. The stakeholder consultation process attempted to seek input from First Nations along with other stakeholders with regard to cost allocation and rate design issues.

3.7.3 Evidence was filed by the Chiefs who stated that they represent the interests of 134 First Nations communities throughout the province. In general, First Nations feel that they have been negatively impacted by the construction of transmission and generation facilities. Their final argument states that "These facilities were built across traditional territory and reserve land without consideration for, or consultation with the Aboriginal people who would be substantially affected by these developments. The compensation paid by Hydro for their Rights-of Way across reserve land was inadequate. In other cases, First Nations were flooded, burial grounds eroded, traditional economies destroyed and entire communities relocated".

3.7.4 The evidence and requests by the Chiefs for a special transmission rate fall into two main categories. The first relates to cost allocation and rate design issues in general and specific rate relief for First Nations communities. The second relates to the development of a protocol. The positions and relief requested are based on the First Nations' position that the Board should address what the Chiefs perceive as a unique historical prejudice.

3.7.5 The cost allocation and rate design issues raised by First Nations are noted and dealt with elsewhere in this Decision. In some cases the Board's findings are in line with the position of First Nations and in other cases they are not. In the latter cases the Board was not persuaded to permit special rate treatment for First Nations. This is consistent with the Board's findings with respect to requests for special rate treatment by other advocates of special interests.

Development of a Protocol

3.7.6 The evidence of the Chiefs states that "First Nations are not seeking redress before the Board [for historical grievances]. They do not want compensation. Rather, it is the desire of the First Nations to take advantage of the opportunities afforded in the *Energy Competition Act, 1998* through the establishment, over time, of commercial organizations active in the generation or distribution of electricity or in the provision of related services".

3.7.7 As a remedy, the Chiefs requested that the Board order the Applicant to develop a protocol in consultation with First Nations to address the First Nations' unique, historical prejudice and provide a framework for the negotiation of contracts establishing commercial businesses in the generation or distribution of electricity prior to open access.

3.7.8 The submission outlines some 17 specific items which it recommends be included in the protocol. They are grouped under two main headings as set out below, which relate to providing management assistance and training and to providing various financial incentives.

3.7.9 The requested actions for management and training assistance that would be included in the protocol are as follows:

- providing copies of the OHNC Distribution company's necessary business and management systems, including training in their application;

- providing maintenance planning procedures;

- providing operating and maintenance procedure manuals; and

- offering specialized trades and support training such as:

  - allotting spaces for First Nations employees in apprenticeship programs
  - computer applications (billing, work and financial reporting, etc.)
  - planning processes and applications
  - work planning
  - performance monitoring.

3.7.10 The financial incentives to be included in the protocol are outlined below:

- selling necessary physical facilities for the creation of a new LDC at book value determined by the specific facilities in question, not the asset pool;

- providing interest free financing for the acquisition of the physical facilities acquired from OHNC Distribution;

- providing engineering services relating to the incorporation of new or upgraded generation into the delivery system at no cost;

- the provision and installation of any equipment necessary to accomplish the necessary physical separation of the new LDC or the incorporation of new generation into the delivery system without cost;

- waiving any connection charges arising from either the creation of a new LDC or the incorporation of new or upgraded generators into the transmission system;

- providing an appropriate discount from standard network charges for a new LDC;

- permitting a new LDC to enter into a contract, either dollar or capacity-based, for periods of up to twenty five years for relevant charges to connect to the transmission grid;

- permitting energy swaps with First Nations generators either on a time (peak, off-peak) or geographic basis;

- charging for any shared low-voltage delivery system necessary to deliver energy to an embedded LDC on the basis of the incremental costs imposed on the delivering LDC; that is, such deliveries will not incur transmission infrastructure costs;

- charging for transmission services arising from the establishment of new upgraded generation with the LDC on a net load basis;

- charging any load customer generation wholly or partially owned by First Nations on a net load basis; and

- charging for the exporting of electricity from generation wholly or partially owned First Nations based on the incremental transaction costs administered by the IMO; that is, such exports do not incur transmission infrastructure costs.

Positions of the Parties

3.7.11 Most intervenors did not comment on this issue. OHNC maintained that special rates for any group of customers including First Nations would result in unfair cost shifting to other customers. OHNC also argued that many of the issues raised are outside of the Board's jurisdiction.

3.7.12 Five Nations Energy supported action by the Board that would lead to negotiations between the Chiefs and OHNC. CAC submitted that a special rate would be inconsistent with rate making principles and that some of the issues are beyond the jurisdiction of the Board. MEA recommended that no special rates be created for any customer. OFA submitted that consideration of special treatment of First Nations be reserved for consideration at a future licence hearing for a transmission or generation facility.

Board Findings

3.7.13 In the Board's view, the Chiefs' evidence and argument regarding their request for a protocol takes a very wide interpretation of the powers of the Board. While the Chiefs do not suggest the Board take action to provide compensation for past grievances, which certainly would be outside of the Board's jurisdiction, they do nonetheless make the sweeping assertion that the Board should "level the playing field so that in future, [First Nations] have an equal opportunity in Ontario's new electricity marketplace to achieve their goal of becoming economically independent self-sufficient communities". The Board does not find a mandate for such sweeping action in the OEB Act. Therefore the Board finds that it lacks the jurisdiction, certainly in the context of a rate setting proceeding, to accede to the Chiefs' request.

3.7.14 The Board does not underestimate the seriousness of the issues raised by the Chiefs. It notes that OHNC has created a Northern Strategies Division that includes responsibility for matters pertaining to First Nations. This may provide an appropriate forum for OHNC, its shareholder and the Chiefs to address issues of mutual concern.

Existing Ontario Hydro Contracts

3.7.15 Throughout the 1990s Ontario Hydro introduced a number of incentive pricing options and special contracts were made available to certain customers. The *Electricity Act* mandates that the former Ontario Hydro contracts, which are now administered by OPG, will cease to have effect upon market opening, unless specifically exempted by the Government. OHNC proposed that all contracts expire at market opening. The concerns of stakeholders with the OHNC proposal centered on three types of contracts: surplus power, load retention and expansion rates, and back-up service. A number of industrial customers submitted that certain terms of some contracts should extend beyond market opening.

3.7.16 Surplus power contracts were intended to utilize then existing surplus capacity by offering special rates to large customers who had flexible operations. The rates applied to incremental, interruptible loads in excess of a historic baseline. At the beginning of 1999 surplus power was available only to existing customers contingent on availability and subject to the impact of the *Electricity Act* and market opening.

3.7.17 Load retention and expansion contracts provided incentives to customers who had economically viable alternatives to service from Ontario Hydro. As a result customers canceled or delayed plans to build their own on-site generation and transmission capacity.

3.7.18 Back-up power rates applied to direct industrial and wholesale customers who provided all or some of their own power needs, but periodically needed to take power from the Ontario Hydro system. The rate was designed to recognize that while Hydro's facilities needed to be maintained they were not actually used very often by the customer.

Position of the Parties

<u>Surplus Power</u>

3.7.19 AMPCO and certain holders of surplus power contracts presented evidence that rate shock would arise from the discontinuance of the existing contracts. A panel of AMPCO members representing surplus power customers presented evidence on the effect of discontinuing the rate and advocated that the Board recommend to the Government that a 10 year phase out be allowed for surplus power contracts.

3.7.20 Certain intervenors opposed the continuation of surplus power contracts beyond market opening on the basis that this would unfairly shift costs and that the intent of the Legislature is clearly spelled out in the *Electricity Act.*

3.7.21 OHNC opposed the continuation of the contracts because of cost shifting to its other customers and on the basis of its belief that the impact on contract holders would be ameliorated by the long run benefits of a competitive energy market.

Load Retention and Expansion

3.7.22 Imperial Oil and AMOCO submitted that they entered into contracts with Ontario Hydro resulting in their cancelling or postponing construction of their own generation facilities. They submitted that OHNC's position on gross load billing precludes their ability to economically construct such facilities in future. Accordingly, they sought a continuation of the preferred rate and an exemption from gross load billing so that they would be in the same position as if they had constructed cogeneration facilities in the first place.

3.7.23 CAC opposed the requested relief on the basis that the Board does not have full information with respect to the impact of such a decision; that the Board only supported the contracts in the first place if they were limited to three years; and, that the intent of the legislation in this matter is clear. Other intervenors pointed out that significant relief will be provided if the Board rules in favour of net load billing.

3.7.24 OHNC stated that it has "some sympathy" for the cases of Imperial Oil and AMOCO and supported the matter being heard by the Board. However, OHNC submitted that the contracts expire only one month after market opening and contain no provisions for extension. Moreover, at the time of negotiations it was understood that the contracts could be negated by legislation some time in the future.

Back-up Power Rates

3.7.25 AMPCO submitted that there should be a separate back-up rate in the event that the charge determinants for network service are not based on variations of coincident peak. For the determination of the back-up rate, AMPCO proposed that discussions take place between the Board, OHNC, the IMO and AMPCO.

3.7.26 OHNC argued that while these contracts were consistent with the old Ontario Hydro monopoly system, under the new regime transmission service provided to occasional users "who happen to have a generator out of service" should be at the same rate as for other occasional users.

Board Findings

3.7.27 The Board has already dealt with the issue of back-up power rates in its discussion of the appropriate charge determinants where the Board found that a separate back-up rate for embedded generation is not warranted at this time.

3.7.28 With regard to the other contracts the Board has not been persuaded that the public interest would be enhanced if it ordered special rate treatment for surplus power or load retention customers, or if it recommended to the Government that these types of contracts be exempt from section 26(3) of the *Electricity Act*, which terminates such contracts upon market opening.

3.7.29 Based on the evidence, these contracts, excluding back-up contracts, cover 1780 MW, equating to some $59 million annually of equivalent network charges. Such an amount would represent a significant cost shift to the rest of the transmission customers. While this may have been warranted by the circumstances that existed at the time of excess power capacity under a monopolistic, bundled electricity regime, under an unbundled, open access regime the circumstances are entirely different. While the Board is sympathetic to the potential impact of the new regime on certain customers or customer groups, it is not uncommon for a major restructuring of the electricity industry to bring about certain unwelcome financial impacts on specific customers or customer groups in the short term.

3.7.30 In any event, the electricity restructuring is intended, among other things, to provide opportunities for customers to better manage their energy requirements. For some customers who have previously enjoyed such special arrangements, the new opportunities presented, including the Board's ruling on certain issues such as net load billing for network services, may offset or partially offset the rate impacts asserted by specific customers or customer groups.

3.7.31 There is no reason to believe that the Government was unaware of the potential implications of its new legislation on the electricity industry. Section 26(3) of the *Electricity Act* which ceases these types of contracts, also specifically allows for an exemption by government regulation. To date, no such exemption regulation has been enacted.

3.7.32 Going forward, this is not to suggest that future circumstances may not warrant consideration of special arrangements dealing with provision of interruptible service. The Board notes OHNC's willingness to discuss with stakeholders the use of lower cost interruptible transmission outside the period of the transmission system peak. The Board does not discourage such attempts. However, any discussions of this nature would have to consider the overall public interest, not just the private interest of a particular customer or a customer group.

3.8 EXPORT AND WHEEL-THROUGH TRANSACTIONS

3.8.1 Imports of power to Ontario customers are assessed charges for the use of the transmission system on the same basis as Ontario generated power. The load customers pay these charges as part of the transmission tariff.

3.8.2 Export of power from Ontario generators (exports) or the pass-through of power from generators located outside Ontario to customers in other jurisdictions (wheel-through), collectively referred to as Export and Wheel-through Transactions (EWT), in addition to paying to the IMO the specific transaction costs, also utilize the assets and facilities of the Ontario transmission system. The issue is how to assess transmission costs to these transactions.

3.8.3 Having considered a number of options, the Company proposed that EWT transactions pay a fixed rate of $1/MWh to be administered by the IMO. The revenue generated by the EWT tariff charges shall be used to reduce the revenue requirement for the network pool in OHNC's subsequent rate filing.

3.8.4 OHNC initially proposed that a credit would be made to generators by an amount equivalent to their contributions to the surplus resulting from the IMO's auction/sale of financial transmission rights (FTRs). This proposal was withdrawn after OHNC considered intervenor arguments on this issue.

3.8.5 Reciprocity related to other jurisdictions (US States, Manitoba and Quebec) is a key factor which OHNC considered in its proposed approach to recovery of the fixed costs of the network. OHNC indicated that its proposed tariff was at the lower end of EWT charges in interconnected export markets. In the longer term EWT charges should be based on reciprocal treatment by neighbouring jurisdictions or a marginal costing approach. As a step towards this, OHNC noted that the Federal Energy Regulatory Commission Order 2000 requires US public utilities to join Regional Transmission Organizations (RTOs) which are anticipated to be established by December 2001.

Positions of the Parties

3.8.6 Through prefiled evidence, OPG proposed that exporters pay the larger of $1/MWh on their export volume or their total net congestion payments for EWT services. Each exporter's total net congestion payments include levied congestion charges plus payments to the IMO from the sale of hedges in the form of Financial Transmission Rights (FTRs), minus payments from the IMO to the exporter if the exporter is also a holder of FTRs. The mechanism is based on the Market Rules and guarantees OHNC a minimum revenue of $1/MWh for EWT services. [Congestion payments in the context of this issue relate to the difference between the higher price that can be obtained in an interconnected jurisdiction compared to the price that can be obtained through a domestic sale. Congestion can arise from the capacity constraints in the inter-tie between interconnected jurisdictions].

3.8.7 OPG noted that net congestion charges go into the FTR clearing account and are rebated to Ontario transmission customers. It is therefore both unnecessary and counter-productive to have an explicit fixed export charge in addition to congestion charges. An EWT charge in OPG's view will actually reduce the funds available to transmission customers by preventing otherwise economic export transactions from occurring.

3.8.8 OPG provided examples how the Market Rules govern the export transactions between Ontario and interconnected power markets and illustrated that congestion payments will provide the majority of revenue to Ontario transmission customers. It also provided examples showing that the sale of FTRs through an IMO auction will result in payments to the FTR holders from congestion on the export inter-tie. The transmission customers will be compensated either by congestion charges or the revenue from the auction/sale of FTRs.

3.8.9 In OPG's view the imposition of a fixed charge for EWT sends the wrong price signals to Ontario exporters and neighbouring jurisdictions and is contrary to the market design recommended by the MDC and the IMO's proposed Market Rules.

3.8.10 OPG submitted that OHNC's EWT proposal is discriminatory, will distort the auction/sale of FTR's and lead to "pancaking" which is contrary to the FERC 2000 Order. OPG explained that pancaking is the result of layering on transmission charges on power transfers across jurisdictions when each applies a separate wheel-through charge.

3.8.11 CAC, Energy Probe, MEA, FOCA and CDU supported OHNC's proposal for a fixed EWT charge of $1/MWh. MEA's support for the OHNC proposal was on an interim basis and conditional on the Board requiring OHNC to investigate and report on incremental charges as soon as possible. The MEA favoured a rebate to generators and supported setting EWT rates through multilateral negotiations.

3.8.12 GEC, VECC, OFA, Northwatch and Pollution Probe submitted that OHNC's proposed $1/MWh was too low and could be seen as subsidizing exporters. They generally supported a fully allocated cost-based EWT tariff of $4.85/MWh that is equivalent to the full network charge. VECC noted that the majority of transactions have historically taken place between Ontario, New York and Michigan where no discounting of EWT charges takes place. VECC submitted that a fully allocated EWT charge would not be a large component of the total power cost and maximization of EWT revenues to the benefit of all transmission customers should be the goal. GEC and Pollution Probe submitted that reduced charges for EWT transactions cannot be justified, are inconsistent with pricing in New York and Michigan, would result in higher exports and therefore more pollution and are not in the interest of Ontario customers. OFA submitted that the perception of an export subsidy could result in trade action by US generators.

3.8.13 AMPCO noted that OHNC's [original] proposal requires the IMO to provide OHNC with customer lists including confidential information in order to issue rebates to generators receiving transmission rights. AMPCO supported a variable tariff administered by the IMO with a maximum rate equal to the average transmission infrastructure cost and a minimum charge based on congestion and IMO charges. The tariff would be matched to the level of charges in each interconnected jurisdiction.

3.8.14 TransCanada Energy submitted that OHNC's proposal does not address reciprocity. As a result of the tariffs proposed for Ontario and those existing in New York (ranging from $1/MWh to $10/MWh) power can find its way inexpensively and easily from Ontario but not as easily find its way in. Although the goal is free flow of power across pool boundaries this must be tempered with present day realities.

3.8.15 IPPSO, Enron and IMO indicated that a fixed EWT tariff was redundant given the working of the export power market and advocated that the Board reject OHNC's proposal. They supported an EWT tariff based on incremental costs for congestion, but without a contribution to embedded network infrastructure costs. They noted that this is the recommendation of the MDC. Enron submitted that under OHNC's proposal some export transactions will not occur, Ontario customers will lose net congestion rental revenues, export opportunities will be impaired and investment in new generation lost. IPPSO submitted that export transactions will contribute to downward pressure on domestic power prices and that applying marginal costs only, more appropriately reflects the values associated with the use of the transmission system by EWT transactions.

3.8.16 OHNC submitted that its proposed EWT charge was a compromise among competing proposals. It indicated that the Ontario regulatory and transmission pricing mechanism is not bound by FERC Orders or the practices of other jurisdictions outside Ontario. Nonetheless and notwithstanding FERC concerns about "pancaking", no North American jurisdiction has yet instituted short run marginal pricing for EWT transactions.

3.8.17 OHNC replied that it had refined its proposal to avoid complexities between collection of transmission infrastructure charges, congestion management and FTRs by the IMO as envisioned under the Market Rules. It also noted that its revised proposal avoids the need for IMO participation in the commercial decision process with respect to the EWT tariff, since the IMO simply applies a fixed rate to all transactions.

3.8.18 OHNC indicated it will monitor transmission tariffs in interconnected jurisdictions and support moves to eliminate the EWT tariff on a reciprocal basis. In the interim, the proposed EWT proposal is non discriminatory, will not distort the FTR market and will reduce concerns about pancaking as per FERC Order 2000.

Board Findings

3.8.19 The tariff/rate for EWT transactions has proven to be a contentious and complex issue. The contention arises from what ought to be the appropriate charge level for exporters that would help defray costs for domestic transmission customers, and from the potential environmental consequences from higher exports. The complexity arises from potential impacts from implementation of competing proposals by OHNC and OPG. In addition, there are issues relating to international trade agreements and reciprocity as well as the MDC's recommendations that resulted from an examination of this issue.

3.8.20 The Board considers that the Government's long-term objective of reducing energy costs through competition can be served by the development of larger, open power markets where trade can take place with the minimum of impediment. In this regard, the Board appreciates the recommendation by the Market Design Committee that EWT transactions should be subject to only incremental transaction-specific charges and no contribution to sunk costs should be levied. However, the feasibility of the MDC recommendation is, in the Board's view, dependent on the pricing policies of the other interconnected jurisdictions.

3.8.21 The evidence indicates that, despite FERC Order 2000, US jurisdictions interconnected to Ontario have not yet fully addressed the issues inherent in the emerging Regional Transmission Organizations (RTOs). As a result, current EWT tariffs in these interconnected jurisdictions, as well as Manitoba and Quebec, cover a wide range of charges (US$1/MWh to approximately US$11/MWh), but which generally exceed the proposed $1/MWh.

3.8.22 While arguments for Ontario taking leadership in not imposing any charges for EWT transactions beyond incremental cost are well intentioned, the Board is of the view that the imposition of a reasonable EWT charge to recover a portion of the transmission costs does not inhibit the further development of a pricing regime based on only incremental cost. Eventually the issue will be resolved by experience and/or in concert with actions in other jurisdictions. Also, it should be noted that according to some opinions offered during the hearing, higher EWT charges could significantly curtail export trade with the result of dampening rather than maximizing congestion and EWT revenues.

3.8.23 The Board does not accept that the EWT charge should be equal to the domestic charge, as advocated mainly by the environmental groups, since such a charge may frustrate the objective of working toward a larger, open power market. While environmental considerations related to power exports are important, as noted elsewhere in this Decision they must be balanced with the other objectives set out for the Board and other well-established rate design objectives. The Board notes the Government’s announcement on May 17, 2000 that it is reviewing the options for environmental protection related to OPG’s coal-fired generation plants.

3.8.24 As the Board has not been persuaded that it would be reasonable at this time to consider a two part rate for each of exports and wheel-through as suggested by one intervenor, this leaves the issue of competing alternatives proposed by OHNC and OPG. The Board appreciates that both OHNC and OPG have made their best efforts to inform and persuade the Board about the issues and benefits of adopting their own proposal. The Board notes the general expectation that, under the Market Rules, the congestion management system of the IMO will yield some net revenue that will be credited to transmission customers (market participants). Assuming these expectations are fulfilled, at this point it is not possible for the Board to assess whether the net revenue arising from the congestion management will be greater or less than the revenue from the $1/MWh flat rate proposed by OHNC or the ceiling proposed by OPG, also $1/MWh. Given all of the other many market opening issues, the Board's preference for OHNC's revised proposal of a flat rate is mainly because of its simplicity.

3.8.25 In summary, the Board finds that as an interim tariff, the OHNC revised proposal is simple, signals that EWT rates are at the low end of the range of tariffs in other interconnected jurisdictions and will allow experience to be gained regarding net revenues generated by the IMO administered inter-tie congestion management system. The Board therefore approves a fixed EWT charge of $1/MWh.

3.8.26 The Board emphasizes the interim nature of this decision and directs OHNC to monitor and report to the Board at OHNC's next main rates case on the functioning of the EWT market and developments in interconnected jurisdictions and whether the interim tariff should be reviewed.

4. IMPLEMENTATION, COMPLETION AND COSTS

4.1 IMPLEMENTATION

4.1.1 OHNC provided the table shown below to indicate the decisions required to implement the transmission rates and the links with other processes for the implementation of rates.

4.1.2 Transmission rates are linked to the **Market Rules** process because it is the Market Rules that set out the IMO's obligation to provide transmission services in Ontario and to collect transmission charges from transmission customers. OHNC stated that its modified proposal on EWT service could be implemented with certain changes to the Market Rules.

4.1.3 The IMO has established a **Billing & Settlements** process in response to various requirements of the Market Rules, including the collection of transmission charges. The Billing & Settlements process will develop the logistical requirements for collecting and settling various charges from electricity customers. OHNC indicated that the wholesale Billing and Settlements process has not yet been finalized and that it has had on-going discussions with the IMO. As a result of these discussions, OHNC believes that the rates and final rate design proposals can be implemented by market opening.

4.1.4 Transmission rates are also linked to the **Transmission System Code** development process, which will define requirements for connection conditions, design, operational and maintenance matters, connection agreements and transmission system expansion. OHNC stated that it is confident that the timely development and approval of the Transmission System Code will not pose a barrier to the implementation of the rates being proposed.

4.1.5 Also, the transmission rates are linked with **Distribution Rate** setting in that the rules for charging transmission rates to end use customers will be defined in that process. Transmission rates billed to distributors by the IMO will be billed to end-use customers as part of the Board's unbundled rate approval process for Distributors. This process is to be completed in time for open access and, according to OHNC, should not prove an impediment for implementation of transmission rates.

	Decisions Requested	**Implementation Links**
Cost Allocation:	Functionalization Methodology Allocation	None None None
Rate Design:	Gross vs Net: - Connection - Network - Existing Embedded Generation - 1 MW Threshold - Efficiency Standard	 Billing and Settlements (IMO) Distribution Rate Setting (LDCs/OEB) Billing and Settlements (IMO) Distribution Rate Setting (LDCs/OEB) None Billing and Settlements (IMO) None
	Charge Determinants: - Connection - Network - EWT	 Billing and Settlements (IMO) Distribution Rate Setting (LDCs/OEB) Billing and Settlements (IMO) Distribution Rate Setting (LDCs/OEB) Billing and Settlements (IMO)
	Definition of Transmission Customer	Billing and Settlements (IMO)
	Treatment of Existing Contracts	None
	Terms and Conditions of Service	Transmission System Code (OEB)
	Treatment of New Load Connection	None
	Treatment of New Generation Connection	Billing and Settlements (IMO)
	First Nations' Special Rate	None

Terms and Conditions of Service - Liability Provision

4.1.6 The Terms and Conditions of Service (the "Terms") applying to OHNC transmission services are to a significant degree dependent on the draft Transmission System Code developed by the OEB Transmission System Code Task Force and, at the time of writing, available for public comment. The Terms are also dependent on the final version of the Market Rules expected to be issued by the IMO prior to market opening.

4.1.7 OHNC filed a draft set of the Terms, but there was insufficient time for the Applicant to answer interrogatories and present witnesses in order to address the issues that were raised by these proposals.

4.1.8 The major issue was that of liability for damages incurred by transmission customers as a result of outages or other actions by OHNC.

4.1.9 AMPCO submitted that the Board reject the Terms because they were not discussed in the stakeholder process. AMPCO submitted that the Board require OHNC to undertake "meaningful stakeholder consultation" on the Terms as part of the Transmission System Code process.

4.1.10 MEA, Inco, Toronto Hydro, OPG, Energy Probe, and CDU submitted that the Board direct that the draft Terms provide that OHNC be liable for direct damages, but not for indirect or consequential damages caused by negligence or intentional wrongdoing by OHNC.

4.1.11 OPG suggested that the Board should ensure that the term "reasonable efforts to restore service" should be the standard and be defined and included in the Terms and/or the Transmission System Code.

4.1.12 The IMO questioned whether OHNC's proposals were consistent with the general liability framework now being developed. The IMO expressed an interest in seeing OHNC's proposed connection agreements in order to enable market testing and operation.

4.1.13 In its Reply Argument OHNC proposed an amended liability clause which, in effect, assumes some liability but only for direct damages as a result of wilful acts, gross negligence or omission by its employees. Other effects including loss of business and indirect damages are not covered and OHNC should not be liable to any transmission customer for indirect or consequential damages, howsoever caused.

4.1.14 OHNC submitted that the proposed Terms form one part of a broader regulatory scheme which will include the provisions of the Market Rules and the Transmission System Code. The proposed OHNC approach may therefore be subject to change depending on the outcome of these processes.

Board Findings

4.1.15 The Board has reviewed the need for OHNC to develop terms and conditions of service and connection agreements in light of the provisions of the draft Transmission System Code. The Board finds that the draft Transmission System Code covers the requirements, including liability provisions, and therefore the Board will not require OHNC to file separate Terms and Conditions of Service or a template for customer Connection Agreements.

Regulatory Plans

4.1.16 OHNC's current transmission rate application was developed under a cost of service framework. It has not proven practical for OHNC to file a fresh rate application during 2000 as previously contemplated. It stated that the approved rates resulting from this proceeding will be in effect until 2002 (application expected in 2001) which may include a proposal for a Performance Based Regulation plan. Given those circumstances, the Applicant proposed that it file a summary of financial results annually on a confidential basis with the Board's Energy Returns Officer in order to keep the Board apprised of the Company's performance relative to the approved revenue requirement.

4.1.17 Certain parties (CAC, MEA, Toronto Hydro, OPG, CDU, Detroit Edison, TransCanada Energy and VECC) commented on OHNC's plans for the next rates hearing and the provision for a PBR plan. The major themes were the need for a cost of service review to serve as a base, a stakeholder consultation process, and the provision of performance data in the interim period.

4.1.18 Certain other parties (OMA, Toronto Hydro and Inco) requested that the Board require OHNC to report to the Board with notice to the parties respecting consistency between the Board's Rate Order and IMO requirements for the purpose of hearing further submissions by parties if necessary.

4.1.19 The IMO indicated it has a significant interest in the performance of transmitters and, in the absence of a PBR scheme, OHNC's technical performance results should be shared rather than kept confidential.

Board Findings

4.1.20 The rates set out in the Board's rate order in this proceeding will be in effect from the opening of the electricity market until changed as a result of a new order. The Board notes the Company's undertaking to file its next application in 2001 for 2002 rates. The Board also notes OHNC's plans to file a Performance Based Regulation plan at that time. The Board is not prepared at this time to provide any other direction to OHNC with respect to its planned rate filing.

4.1.21 The Board notes OHNC's plan to file with the Board's Energy Returns Officer its financial performance relative to the approved revenue requirement. The Board expects the Energy Returns Officer to define the specifics of the reporting required. With respect to the issue of confidentiality the Board notes that such filings are treated on a confidential basis.

4.1.22 Based on the evidence provided by OHNC and the submissions of the IMO, the Board has not identified any areas of inconsistency between the Board's Decision and the IMO's Market Rules as they stood at the completion of the argument phase of the hearing. Out of an abundance of caution the Board expects OHNC to consult with the IMO prior to filing a draft Rate Order.

4.2 COMPLETION OF PROCEEDINGS

4.2.1 The Applicant has a valid Transitional Rate Order that sets out the revenue requirements for its fiscal years 1999 and 2000. The current Rate Order applies to bundled bulk power delivery and includes an implicit two part transmission tariff as part of that Order. These bundled rates must be replaced upon market opening.

4.2.2 This proceeding will result in a new Rate Order based on the Board-approved fiscal year 2000 revenue requirement of $1.182 billion, set out in the Board's Letter of Direction, dated March 1, 2000 and incorporating the transmission rates designed to collect this revenue requirement as set out in this Decision.

4.2.3 The Board directs OHNC to file a draft Rate Order along with draft rate schedules, and customer notices as soon as possible but no later than August 15, 2000. The draft Rate Order shall contain the appropriate rates to reflect the Board's findings in this Decision, including a draft accounting order to record the EWT revenues. The prescribed latest date is chosen to allow for the other related processes to be completed in the near future.

4.2.4 In accordance with the Board's current practice, intervenors in RP-1999-0044 will be afforded an opportunity to comment on the draft Rate Order. Upon filing its draft Rate Order OHNC will notify all intervenors who may then inspect the draft at the Board's Offices and may then provide written comments to the Board within 10 working days from the date of notification.

4.2.5 Once the Transmission System Code is available, OHNC shall make explicit reference in the rate schedules to the applicable parts of the Transmission System Code, including the Connection Agreement.

4.2.6 The Board notes that, although not essential under cost of service regulation, OHNC does not have a set of transmission system performance indicators specified in the current rate order. Accordingly, although the Board had reservations about the proposed performance measures filed as part of the RP-1998-0001 application, given the need to establish a baseline for a future PBR plan, it directs OHNC to record and file with the Board, with a copy to the IMO, its performance against the set of proposed performance indicators filed in the RP-1998-0001 application. The Board expects the Energy Returns Officer to specify the frequency of such reporting. The Board notes that requirements for customer level performance standards are set out in the Transmission System Code and views these to be complementary to the system-wide performance indicators the Board is directing OHNC to monitor and report.

4.3 COST AWARDS

4.3.1 For purposes of expediting the issuance of this Decision, the Board will issue a supplemental Decision on cost awards.

DATED AT Toronto, May 26, 2000.

R.M.R. Higgin
Presiding Member

P. Vlahos
Vice Chair

B.A. Smith
Member