Manitoba Hydro 2010/11 & 2011/12 GRA
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26 PRE 1997

"supply" includes delivery, dealing in, and sale; ("fournir")

"works" includes all roads, railroads, plant, machinery, buildings, structures, erections, constructions, installations, materials, devices, fittings, apparatus, appliances, equipment, and other property for the development, generation, transformation, transmission, distribution, or supply of power. ("ouvrages")

"Régie" La Régie de l'hydro-électricité du Manitoba prorogée par la présente loi. ("corporation")

"Sa Majesté" Sa Majesté la Reine du chef de la province du Manitoba. ("Her Majesty")

"site de production" Y sont assimilés les biens-fonds, lacs, rivières, ruisseaux, cours d'eau, étendues d'eau, les licences ou les privilèges relatifs à l'eau, les réservoirs, les barrages, les vannes, les canaux, les biefs, les tunnels ou les aqueducs qui servent ou peuvent être utilisés directement ou indirectement à la mise en exploitation ou à la production d'énergie. ("power site")

Intent, purpose, and object of Act.
2 The intent, purpose, and object of this Act is to provide for the continuance of a supply of power adequate for the needs of the province, and to promote economy and efficiency in the generation, distribution, supply, and use of power.

Esprit, but et objet de la Loi
2 L'esprit, le but et l'objet de la présente loi sont d'assurer la fourniture d'énergie dont la province a besoin et de promouvoir l'économie et l'efficacité dans son processus de production, de distribution, de fourniture et d'utilisation.

PART I
THE CORPORATION

PARTIE I
LA RÉGIE

Continuation of corporation.
3 The corporation as heretofore constituted, established, and incorporated shall continue to be a body corporate consisting of the members of the board.

Prorogation de la Régie
3 La Régie telle qu'elle a été établie et constituée en corporation est prorogée en tant que personne morale composée des membres du conseil.

References to "Manitoba Hydro".
4(1) The corporation may be referred to, or shortly described, in Acts of the Legislature and otherwise, as: "Manitoba Hydro".

Hydro-Manitoba
4(1) La Régie peut être citée sous le nom de "Hydro-Manitoba", que ce soit dans les lois de la Législature ou ailleurs.

Agency of Crown subject to certain limitations.
4(2) The corporation is an agent of Her Majesty; but, subject to subsection (4), may sue and be sued, contract and be contracted with, in and by its corporate name as in the case of any other corporation.

Limite au statut d'agent de la Couronne
4(2) La Régie est agent de Sa Majesté. Toutefois, sous réserve du paragraphe (4), la Régie peut ester en justice et contracter sous sa dénomination sociale, de la même manière que toute autre corporation.

Holding of property.
4(3) Property owned or acquired by the corporation shall be held or acquired in the name of the corporation.

Possession de biens
4(3) Les biens dont la Régie est propriétaire ou ceux qu'elle acquiert sont détenus ou acquis au nom de la Régie.

"separation of functions" means the functions of

(a) the corporation,

(b) any subsidiary, or

(c) any other person,

as determined by the board, operated on an independent and separate basis by the corporation, any subsidiary, any other person or any combination thereof; (« séparation des fonctions »)

"subsidiary" means a company of which the corporation owns, directly or indirectly, all of its shares; (« filiale »)

"supply" includes delivery, dealing in, and sale; (« fournir »)

"works" includes all roads, railroads, plant, machinery, buildings, structures, erections, constructions, installations, materials, devices, fittings, apparatus, appliances, equipment, and other property for the development, generation, transmission, distribution, or supply of power. (« ouvrages »)

S.M. 1993, c. 29, s. 187; S.M. 1997, c. 55, s. 2.

« Régie » La Régie de l'hydro-électricité maintenue par la présente loi et dénommée par ailleurs « Hydro-Manitoba ». ("corporation")

« Sa Majesté » Sa Majesté la Reine du chef de la province du Manitoba. ("Her Majesty")

« séparation des fonctions » Les fonctions de la Régie, d'une filiale ou d'une autre personne que détermine le conseil et que la Régie, la filiale ou l'autre personne, ou une combinaison d'entre elles, dirige de façon indépendante et distincte. ("separation of functions")

« site de production » Y sont assimilés les biens-fonds, lacs, rivières, ruisseaux, cours d'eau, étendues d'eau, les licences ou les privilèges relatifs à l'eau, les réservoirs, les barrages, les vannes, les canaux, les biefs, les tunnels ou les aqueducs qui servent ou peuvent être utilisés directement ou indirectement à la mise en exploitation ou à la production d'énergie. ("power site")

L.M. 1993, c. 29, art. 187; L.M. 1997, c. 55, art. 2.

Purposes and objects of Act

2 The purposes and objects of this Act are to provide for the continuance of a supply of power adequate for the needs of the province, and to engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of power and, in addition, are

(a) to provide and market products, services and expertise related to the development, generation, transmission, distribution, supply and end-use of power, within and outside the province; and

(b) to market and supply power to persons outside the province on terms and conditions acceptable to the board.

S.M. 1997, c. 55, s. 3.

Objets de la présente loi

2 La présente loi a pour objets d'assurer le maintien d'une réserve d'énergie permettant de répondre aux besoins de la province, et de développer l'exploitation, la production, le transport, la distribution, la fourniture et l'utilisation finale de l'énergie et de promouvoir l'économie et l'efficacité dans ces opérations; elle a également pour objets :

a) de fournir et de commercialiser des produits, des services et des compétences ayant trait à l'exploitation, à la production, au transport, à la distribution, à la fourniture et à l'utilisation finale de l'énergie, tant à l'intérieur qu'à l'extérieur de la province;

b) de commercialiser l'énergie et d'en fournir aux personnes de l'extérieur de la province à des conditions que juge acceptables le conseil.

L.M. 1997, c. 55, art. 3.

(c) to every person, company, or corporation, and local authority owning, operating, or controlling any public utility, including any railway, street railway, or tramway, to which the jurisdiction of the Legislature extends.

c) à toute personne, compagnie ou corporation et à toute autorité locale possédant, exploitant ou contrôlant un service public, y compris un chemin de fer, un chemin de fer vicinal ou un tramway relevant de la compétence de la Législature.

Pipeline under Oil and Gas Act
2(2) Notwithstanding subsection (1), a pipeline to which The Oil and Gas Act applies is not a public utility until it is declared under clause (4)(b) to be a public utility.

Pipeline -- Loi sur le pétrole et le gaz naturel
2(2) Par dérogation au paragraphe (1), les pipelines auxquels la Loi sur le pétrole et le gaz naturel s'applique ne sont pas considérés comme des services publics tant qu'ils ne font pas l'objet d'une déclaration en vertu de l'alinéa (4)b).

Exception for gas etc. in tanks
2(3) Notwithstanding the definition "public utility", but subject to subsection (4), any system, works, plant, pipe line, equipment or service for the production, transmission, delivery or furnishing of gas, whether natural or manufactured, oil or other fluid petroleum products, or water,

(a) sold and delivered in tanks, cans, bottles, or other containers; or

(b) delivered by means other than pipe lines, using streets, lanes or highways;

is not a public utility.

Autre exception
2(3) Par dérogation à la définition de «service public», mais sous réserve du paragraphe (4), n'est pas un service public un système, ouvrage, installation, pipeline, équipement ou service servant à la production, la transmission, la livraison ou la fourniture de gaz naturel ou manufacturé, de pétrole ou autres produits pétroliers liquides, ou de l'eau, qui sont, selon le cas :

a) vendus et livrés en réservoirs, bidons, bouteilles ou autres contenants;

b) livrés autrement que par des pipelines, en utilisant des rues, ruelles ou routes.

L.G. in C. may declare public utility
2(4) The Lieutenant Governor in Council may declare

(a) a system, works, plant, pipe line, equipment or service to which subsection (3) applies; or

(b) a pipeline to which The Oil and Gas Act applies;

to be a public utility, and thereupon the system, works, plant, pipe line, equipment, service or pipeline is a public utility under this Act.

Déclaration à titre de services publics
2(4) Le lieutenant-gouverneur en conseil peut déclarer à titre de services publics :

a) les réseaux, les installations, les usines, les pipelines, l'équipement et les services visés au paragraphe (3);

b) les pipelines visés par la Loi sur le pétrole et le gaz naturel.

Ces ouvrages et services deviennent des services publics dès la prise de la déclaration.

Application to Manitoba Hydro
2(5) Subject to Part IV of The Crown Corporations Public Review and Accountability Act and except for the purposes of conducting a public hearing in respect of an application made to the board under subsection 38(2) or 50(4) of The Manitoba Hydro Act, this Act, other than subsection 83(4) and the regulations under that subsection, does not apply to Manitoba Hydro and the board has no jurisdiction or authority over Manitoba Hydro.

Application à Hydro-Manitoba
2(5) Sous réserve de la partie IV de la Loi sur l'examen public des activités des corporations de la Couronne et l'obligation redditionnelle de celles-ci et sauf aux fins de la tenue d'une audience publique se rapportant à une demande présentée à la Régie en vertu du paragraphe 38(2) ou 50(4) de la Loi sur l'Hydro-Manitoba, la présente loi, à l'exception du paragraphe 83(4) et des règlements pris en vertu de ce paragraphe, ne s'applique pas à Hydro-Manitoba; celle-ci n'est pas non plus soumise à la compétence ni à l'autorité de la Régie.

SALE OF POWER

Price of power sold by corporation
39(1) The prices payable for power supplied by the corporation shall be such as to return to it in full the cost to the corporation, of supplying the power, including

(a) the necessary operating expenses of the corporation, including the cost of generating, purchasing, distributing, and supplying power and of operating, maintaining, repairing, and insuring the property and works of the corporation, and its costs of administration;

(b) all interest and debt service charges payable by the corporation upon, or in respect of, money advanced to or borrowed by, and all obligations assumed by, or the responsibility for the performance or implementation of which is an obligation of the corporation and used in or for the construction, purchase, acquisition, or operation, of the property and works of the corporation, including its working capital, less however the amount of any interest that it may collect on moneys owing to it;

(c) the sum that, in the opinion of the board, should be provided in each year for the reserves or funds to be established and maintained pursuant to subsection 40(1).

Fixing of price by corporation
39(2) Subject to Part IV of *The Crown Corporations Public Review and Accountability Act* and to subsection (2.1), the corporation may fix the prices to be charged for power supplied by the corporation.

Equalization of rates
39(2.1) The rates charged for power supplied to a class of grid customers within the province shall be the same throughout the province.

Interpretation
39(2.2) For the purpose of subsection (2.1),

(a) grid customers are those who obtain power from the corporation's main interconnected system for transmitting and distributing power in Manitoba; and

VENTE D'ÉNERGIE

Prix de l'énergie vendue par la Régie
39(1) Le prix de l'énergie que vend la Régie doit lui permettre de couvrir tous les coûts que la fourniture de cette énergie entraîne pour elle et, notamment :

a) les dépenses nécessaires d'exploitation de la Régie, y compris les coûts de production, d'achat, de distribution et de fourniture d'énergie ainsi que les coûts de fonctionnement, d'entretien, de réparation et d'assurance des biens et des ouvrages de la Régie et ses frais de gestion;

b) les intérêts et les frais reliés aux dettes de la Régie en fonction directe ou indirecte des sommes qui lui ont été avancées ou qu'elle a empruntées, les obligations qu'elle assume ou dont elle se porte responsable de l'exécution ou de la mise en oeuvre lorsque ces sommes sont utilisées pour la construction, l'acquisition ou l'exploitation de biens et ouvrages de la Régie, y compris son fonds de roulement diminué, cependant, du montant des intérêts qu'elle peut retirer à raison des sommes qui lui sont dues;

c) le montant qui, de l'avis du conseil, est nécessaire à chaque exercice pour les réserves ou les fonds que le conseil doit établir et maintenir conformément au paragraphe 40(1).

Pouvoir de la Régie de fixer les prix
39(2) Sous réserve de la partie IV de la *Loi sur l'examen public des activités des corporations de la Couronne et l'obligation redditionnelle de celles-ci* ainsi que du paragraphe 2(1), la Régie a compétence pour fixer les prix de l'énergie qu'elle fournit.

Péréquation des prix
39(2.1) Le prix de l'énergie vendue à une catégorie de clients branchés au réseau de la province est le même partout dans la province.

Définition
39(2.2) Pour l'application du paragraphe (2.1) :

a) les clients branchés au réseau reçoivent leur énergie du réseau d'interconnexion principal de la Régie servant au transport et à la distribution de l'énergie au Manitoba;

PART IV

PUBLIC UTILITIES BOARD
REVIEW OF RATES

Hydro and MPIC rates review
26(1) Notwithstanding any other Act or law, rates for services provided by Manitoba Hydro and the Manitoba Public Insurance Corporation shall be reviewed by The Public Utilities Board under *The Public Utilities Board Act* and no change in rates for services shall be made and no new rates for services shall be introduced without the approval of The Public Utilities Board.

Definition, "rates for services"
26(2) For the purposes of this Part, **"rates for services"** means

(a) repealed, S.M. 1995, c. 33, s. 5;

(b) in the case of Manitoba Hydro, prices charged by that corporation with respect to the provision of power as defined in *The Manitoba Hydro Act*;

(c) in the case of the Manitoba Public Insurance Corporation, rate bases and premiums charged with respect to compulsory driver and vehicle insurance provided by that corporation.

Application of Public Utilities Board Act
26(3) *The Public Utilities Board Act* applies with any necessary changes to a review pursuant to this Part of rates for services.

Factors to be considered, hearings
26(4) In reaching a decision pursuant to this Part, The Public Utilities Board may

(a) take into consideration

(i) the amount required to provide sufficient moneys to cover operating, maintenance and administration expenses of the corporation,

(ii) interest and expenses on debt incurred for the purposes of the corporation by the government,

(iii) interest on debt incurred by the corporation,

PARTIE IV

EXAMEN DES TARIFS PAR
LA RÉGIE DES SERVICES PUBLICS

Examen des tarifs
26(1) Malgré toute autre loi ou règle de droit, les tarifs afférents aux services fournis par l'Hydro-Manitoba et la Société d'assurance publique du Manitoba sont examinés en vertu de la *Loi sur la Régie des services publics* par la Régie des services publics et aucun changement dans ces tarifs ne peut être effectué de même qu'aucun nouveau tarif ne peut être introduit sans l'approbation de celle-ci.

Sens de « tarifs »
26(2) Pour l'application de la présente partie, le terme « **tarifs** » s'entend :

a) abrogé, L.M. 1995, c. 33, art. 5;

b) dans le cas de l'Hydro-Manitoba, des prix fixés par cette corporation relativement à la fourniture d'énergie au sens de la *Loi sur l'Hydro-Manitoba*;

c) dans le cas de la Société d'assurance publique du Manitoba, des bases de taux utilisées ainsi que des primes exigées à l'égard de l'assurance-automobile obligatoire fournie par cette corporation.

Application de certaines dispositions
26(3) La *Loi sur la Régie des services publics* s'applique, avec les adaptations de circonstance, à tout examen que vise la présente partie et qui porte sur les tarifs afférents à des services.

Éléments à considérer
26(4) Afin de prendre une décision en vertu de la présente partie, la Régie des services publics peut :

a) tenir compte :

(i) des besoins financiers de la corporation pour qu'elle puisse assumer ses dépenses de fonctionnement, d'entretien et d'administration,

(ii) des intérêts et des frais relatifs aux dettes que le gouvernement contracte pour les besoins de la corporation,

(iii) des intérêts sur les dettes de la corporation,

(iv) reserves for replacement, renewal and obsolescence of works of the corporation,

(v) any other reserves that are necessary for the maintenance, operation, and replacement of works of the corporation,

(vi) liabilities of the corporation for pension benefits and other employee benefit programs;

(vii) any other payments that are required to be made out of the revenue of the corporation,

(viii) any compelling policy considerations that the board considers relevant to the matter,

(ix) any other factors that the board considers relevant to the matter; and

(b) hear submissions from any persons or groups or classes of persons or groups who, in the opinion of the board, have an interest in the matter.

(iv) des sommes à mettre en réserve pour le remplacement, la rénovation et le vieillissement économique des ouvrages de la corporation,

(v) des autres sommes à mettre en réserve qui sont nécessaires à l'entretien, à l'exploitation et au remplacement des ouvrages de la corporation,

(vi) des obligations de la corporation relativement aux programmes d'avantages destinés aux employés, y compris les prestations de pension,

(vii) des autres paiements qui doivent être faits sur les revenus de la corporation,

(viii) des considérations de principe importantes qu'elle estime pertinentes à l'affaire,

(ix) des autres éléments qu'elle estime pertinents à l'affaire;

b) entendre les présentations des personnes, des groupes ou des catégories de personnes ou de groupes qui, à son avis, ont un intérêt dans l'affaire.

MPIC

26(5) In the case of a review pursuant to this Part of rates for services of the Manitoba Public Insurance Corporation, The Public Utilities Board may take into consideration, in addition to factors described in subsection (4), all elements of insurance coverage affecting insurance rates.

S.M. 1995, c. 33, s. 5.

Société d'assurance publique

26(5) Dans le cas d'un examen visé à la présente partie et portant sur les tarifs afférents aux services de la Société d'assurance publique du Manitoba, la Régie des services publics peut prendre en considération, en plus des éléments mentionnés au paragraphe (4), tous les éléments de la garantie d'assurance qui touchent les taux d'assurance.

L.M. 1995, c. 33, art. 5.

Multi-year approvals

27(1) A corporation may submit for the approval of The Public Utilities Board pursuant to this Part proposals regarding rates for services relating to a period of not more than three years and the board shall identify in its order the change approved, if any, with respect to each year.

Approbation portant sur plus d'une année

27(1) Une corporation peut soumettre à l'approbation de la Régie des services publics conformément à la présente partie des propositions concernant les tarifs afférents aux services qu'elle fournit et portant sur une période maximale de trois ans; la Régie précise dans son ordonnance le changement qui est approuvé, le cas échéant, à l'égard de chaque année.

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Indexed as:

Manitoba (Public Utilities Board) v. Manitoba (Attorney-General) (Man. C.A.)

IN THE MATTER OF The Public Utilities Board Act, R.S.M. 1987, c. P280
AND IN THE MATTER OF The Crown Corporations Public Review and Accountability and Consequential Amendments Act, S.M. 1988, c. C336
AND IN THE MATTER OF The Manitoba Hydro Act, R.S.M. 1987, c. H190
AND IN THE MATTER OF Certain questions respecting the jurisdiction of The Public Utilities Board of Manitoba

Between
The Public Utilities Board, Applicant, and
The Attorney-General of Manitoba, Manitoba Hydro, Manitoba Society of Seniors, Consumers Association of Canada (Manitoba), and The City of Winnipeg, (Intervenors) Respondents

[1989] M.J. No. 491
Suit No. 257/89
61 Man. R. (2d) 164

Manitoba Court of Appeal
Monnin C.J.M., O'Sullivan and Twaddle JJ.A.

October 3, 1989

Administrative law — Judicial review — Board having no power to approve, reject or vary capital projects of Hydro as part of its rate review jurisdiction as power not specifically stated in statute — Crown Corporations Public Review and Accountability and Consequential Amendments Act, S.M. 1988, c. 23, s. 26(1) — Public Utilities Board Act, R.S.M. 1987, c. P-280, s. 58.1.

This was an application by way of a stated case for determination of the following question: whether the Public Utilities Board had jurisdiction to approve, reject or vary Manitoba Hydro project plans incidental to or as a condition of granting approval for changes in the prices charged for power. The Board was under a duty to review and approve all future rates charged for electricity. It was agreed by all counsel that the Act in question granted no such specific power to the Board. The legislation was silent on the issue. It was argued that the Court ought to imply such power in the Board.

HELD: The question was answered in the negative. The Board had no such jurisdiction. The Court was unable to imply such an intention in the legislation as it stood.

W.C. Gardner, Q.C., and P.L. Jensen, for Public Utilities Board.
R.A.L. Nugent, Q.C., and R.E. Roth, for Manitoba Hydro.
A. Peltz, for Manitoba Association of Seniors and Consumers Assoc. of Canada (Manitoba).

Reasons for judgment delivered by Monnin C.J.M., answering the question in the negative; concurred in by O'Sullivan J.A. Separate reasons for judgment delivered by Twaddle J.A., declining to answer the question contained in the Stated Case.

MONNIN C.J.M. (orally):— At the request of counsel for The Manitoba Society of Seniors and The Consumers Association of Canada (Manitoba), the Public Utilities Board has stated a case to the court pursuant to s. 58.1(1) of its Act.

The question for the court is the following:

> Does the Public Utilities Board have jurisdiction to approve, reject or vary Manitoba Hydro capital project plans such as plans to construct new generating stations, incidental to or as a condition of granting approval for changes in the prices charged for power?

Under The Crown Corporations Public Review and Accountability and Consequential Amendments Act, S.M. 1988, c. C336, the Public Utilities Board now has the duty to review and to approve all future rate charges for electricity, and no new rates and no changes in rates shall be introduced without the approval of the Board.

Mr. Peltz, counsel for the Manitoba Society of Seniors, contends that in fixing or reviewing rates the Board has jurisdiction to review the decisions of Manitoba Hydro with respect to its major capital projects such as the construction of new generating stations or new transmission lines.

It is agreed by all counsel that the Act in question grants no such specific power to the Board. In other words, the legislation is silent on that issue. However, Mr. Peltz alleges that the practical reality is that capital plans and expenditures cannot be ignored in any workable system of rate review and if specific legislation is not available, then the court should, of necessity, imply such power in the Board.

I am unable to imply such an intention in the legislation as it stands. To imply it would be to legislate which is not the function of this court. Since the legislation is defective in that the power is not specifically stated, the Board and/or the parties will have to knock at the Legislature's door in order to obtain that specific power if desirable.

On the basis of the legislation as it stands, the Board has no jurisdiction to approve, reject or vary Manitoba Hydro's major capital projects such as construction of new generating power stations or transmission lines.

The answer to the question is therefore in the negative.

This is not a case for an award of costs.

MONNIN C.J.M.
O'SULLIVAN J.A.:— I agree.

The following is the judgment of

TWADDLE J.A. (orally):-- This matter comes before us by way of a case stated by The Public Utilities Board pursuant to s. 58.1 of The Public Utilities Board Act, R.S.M. 1987, c. P280 as amended by The Crown Corporations Public Review and Accountability and Consequential Amendments Act, S.M. 1988, c. 23. A preliminary objection to the proceedings is taken by Manitoba Hydro which contends that the question asked of the Court, in the Stated Case, is not properly before it as there is no proceeding before the Board in which the question arises.

Section 58.1 of The Public Utilities Board Act provides:
"58.1(1) The [Public Utilities] Board may, of its own motion or on the application of any party to proceedings before the board, state a case in writing for the opinion of the Court of Appeal upon any question of law or jurisdiction.
58.1(2) The Court of Appeal shall hear and determine the stated case and remit it to the board with its opinion.
58.1(3) A case stated pursuant to this section does not stay or suspend any proceedings of the board or stay or suspend the operation of any decision or order of the board."

The case stated by the Board, purportedly under that section, arose out of proceedings before the Board pursuant to subsection 26(1) of The Crown Corporations Public Review and Accountability and Consequential Amendments Act, which provides:

"26(1) Notwithstanding any other Act or law, rates for services provided by The Manitoba Telephone System, Manitoba Hydro and the Manitoba Public Insurance Corporation shall be reviewed by The Public Utilities Board under The Public Utilities Board Act and no change in rates for services shall be made and no new rates for services shall be introduced without the approval of The Public Utilities Board."

In the course of those proceedings, Manitoba Hydro acknowledged that

> ". . . [M]ajor plant additions, particularly in the post-Limestone period will be a significant variable affecting rates. Accordingly, Manitoba Hydro proposes that at a future hearing, intervenors and the public have an opportunity to review Manitoba Hydro's long-term capital plans and strategic alternatives for meeting load growth in the late 1990's and beyond. The future review would take place prior to commitment to the recommended option."

It was Manitoba Hydro's position that the Board might make recommendations as to the plans of Hydro involving capital commitments for future projects, but that the Board had neither direct jurisdiction, nor jurisdiction incidental to its rate fixing power, to approve, reject or vary any of those plans.

The Manitoba Society of Seniors and the Consumers Association of Canada (Manitoba) (hereinafter referred to together as "the objectors") gave notice, through counsel, that the objectors reserved the right to move that the matter of the Board's powers or jurisdiction to review decisions on major capital projects be submitted to this Court by way of stated case. Later in the proceedings, before there arose any issue on which the Board might be invited to decide the scope of its powers, the objectors asked the Board to state a case.

Although no issue requiring an answer to the question had actually arisen in the proceedings then before it, the Board did refer the following question to this Court for its opinion:

> "25. Pursuant to the provisions of Part IV of The Crown Corporations Public Review and Accountability and Consequential Amendments Act, does the Public Utilities Board have jurisdiction to approve, reject or vary Manitoba Hydro capital project plans such as plans to construct new generating stations, incidental to or as a condition of granting approval for changes in the prices charged for power?"

The Board dealt with the rate approval application then before it without reference to the issues raised by the question now asked of this Court.

The purpose of a statutory provision enabling an adjudicative tribunal, such as the Board, to state a case for the consideration of this Court is to enable the Board to ascertain the scope of its jurisdiction, or the proper law on a question before it, prior to it making a decision. Although an appeal might be taken from a decision made without a stated case, the appeal may not be decided until too late to avoid adverse affects on the public interest.

In my opinion, the statutory power to state a case is limited to stating a case on an issue which actually arises before the Board and which must be decided in order that a decision can be made. Otherwise, the Board may ask the Court's opinion on a matter which is not based on a real factual situation, but on assumptions or on speculation. Moreover, the question must be sufficiently specific that the one answer covers all possible factual situations that may arise. Abstract questions, interesting as they may be, should not be answered by a court.

The Board, in the matter before us, has anticipated an issue as to its jurisdiction. Although in a general way, I am inclined to the view expressed by my Lord, I am not prepared to say whether the Board lacks jurisdiction, in every possible circumstance, to disapprove a future project of Hydro by disallowing a current expense item. Nor am I prepared to say, on the material before us, whether the Board may review Hydro's plans for the future, but not indicate, in a rate adjustment, that it rejects a particular plan. It would be speculation on my part to foresee how that issue might arise and what I then might find the jurisdiction to be.

I am mindful of the language used, albeit in other circumstances, by the Lord Chancellor, Lord Halsbury, in advising His Majesty on behalf of the Privy Council in Attorney-General Ontario v. Hamilton Street Rlwy. Co., [1903] A.C. 524 at p. 529:

> ". . . [I]t would be inexpedient and contrary to the established practice of this Board to attempt to give any judicial opinion upon those questions. They are questions proper to be considered in concrete cases only; and opinions expressed upon the operation of the sections referred to, and the extent to which they are applicable, would be worthless for many reasons. They would be worthless as being speculative opinions on hypothetical questions. It would be contrary to principle, inconvenient, and inexpedient that opinions should be given upon such questions at all. When they arise, they must arise in concrete cases, involving private rights; and it would be extremely unwise for any judicial tribunal to attempt beforehand to exhaust all possible cases and facts which might occur to qualify, cut down, and override the operation of particular words when the concrete case is not before it."

For these reasons, I would decline to answer the question contained in the Stated Case.

TWADDLE J.A.

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MANITOBA HYDRO 2008/2009 POWER RESOURCE PLAN

The objectives of the 2008/09 Power Resource Plan are as follows:
- Provide a recommended development plan including the WPS and MP sales.
- Provide an alternative long-term development plan, which does not include the WPS and MP sales.

2008/09 Development plan including the WPS and MP sales

The recommended development plan for major infrastructure and resources to facilitate the WPS and MP sales is as follows:

- Near-term (pre 2015) deficits to be filled with contracted imports.
- Keeyask for a 2018 ISD (In-Service Date)
- Conawapa for a 2022 ISD.
- Bipole III as well as any additional north-south transmission beyond 2000 MW sufficient for new northern generation.

In addition to these resources, Manitoba Hydro as been authorized to enter into negotiations for the purchase of 300 MW of wind power.

This development plan reflects signed term sheets with Northern States Power (NSP) for 375/500 MW starting in 2015, Wisconsin Public Service (WPS) for 500 MW starting in 2018, and Minnesota Power (MP) for 250 MW starting in 2022. These Sales provide economic and other strategic benefits. In order to fulfill the terms of these proposed sales, the following are required:
- a new interconnection to Minnesota and Wisconsin by 2018,
- new hydraulic generation in Manitoba, and
- sufficient transmission from the new hydraulic generation to southern Manitoba.

The following summarizes major planned infrastructure and identifies additional planned supply initiatives:

Supply-Side Enhancement Projects (SSE)

Planned Additional:	Total:	226 MW/	273 GW.h by Mar 2018	
Kelsey Rerunnering		77 MW/	0 GW.h by 2012/13	
HVDC Bipole III Line (West)		89 MW/	243 GW.h by 2017/18	
Winnipeg River Plants		30 MW/	30 GW.h	
License Review and Continued Operation:	Total:	357 MW/	2517 GW.h	
Selkirk #1-2		132 MW/	1060 GW.h	*
Brandon #5 Licence Review		105 MW/	837 GW.h	to 2018/19
Pointe du Bois (Rebuild)		120 MW/	620 GW.h	2016/17 (total plant)

*Generation at Selkirk is assumed to be available on a continuous basis throughout the planning time frame due to expected infrequent operation.

Demand Side Management Program (DSM)

Planned additional (by Mar 2018)	180 MW/ 837 GW.h	

New Generation

Hydro:			
Wuskwatim	200 MW gross	200 MW net	2011/12
Keeyask	695 MW gross	630 MW net	2018/19
Conawapa	1485 MW gross	1300 MW net	2022/23
Wind:			
Wind Farm	300 MW		2010/11

Uncommitted projects in the plan are subject to corporate approval based on individual project evaluations prior to each stage in the development process. The definitive agreements being negotiated in good faith from the Sales Term Sheets are subject to Manitoba Hydro approval.

Tables A1.a at the end of this document details the annual energy supply and demand values of this plan. Table A1.b details the annual capacity supply and demand values of this plan.

2008/09 Alternative development plan without the WPS and MP sales

The alternative development plan for major infrastructure and resources to meet Manitoba requirements without the MP or WPS Sales is as follows:

- Near-term (pre 2015) deficits to be filled with contracted imports.
- 400 MW Combined Cycle Gas Turbine for 2019 ISD
- Conawapa for a 2021 ISD.
- Bipole III

In addition to these resources, Manitoba Hydro as been authorized to enter into negotiations for the purchase of 300 MW of wind power.

Further studies are required to fully develop this alternative plan.

Tables A.2a at the end of this document details the annual energy supply and demand values of this plan. Table A2.b details the annual capacity supply and demand values of this plan.

MANITOBA HYDRO 2009/2010 POWER RESOURCE PLAN

Date: September 16, 2009

The purpose of this power resource plan is:

- To provide a recommended long-term development plan, and
- To provide an alternative long-term development plan, in recognition of the uncertainties associated with the recommended plan.

2009/10 Recommended Power Resource Development Plan

The recommended development plan for major infrastructure and resources to pursue a new interconnection and facilitate the Wisconsin Public Service (WPS) and Minnesota Power (MP) sales is as follows:

- The 500 MW Sale to WPS and the 250 MW Sale to MP as described in the Term Sheets in effect.
- Keeyask for a 2018/19 ISD (In-Service Date)
- Conawapa for a 2022/23 ISD.
- A 1000 MW export and 750 MW import interconnection with a 2018/19 ISD.
- Additional north-south transmission beyond a 2000 MW Bipole III, as required for both Conawapa and Keeyask with a 2023/24 ISD.
- The 375/500 MW Sale to Northern States Power (NSP) as described in the Term Sheet in effect.
- 300 MW of additional wind generation with a 2010/11 ISD.
- Wuskwatim with a 2011/12 ISD.
- Pointe du Bois rebuilt with a 2016/17 ISD.

Table 1a at the end of this document details the annual dependable energy supply and demand values of this plan. Table 1b details the annual winter peak capacity supply and demand values of this plan.

2009/10 Alternative Power Resource Development Plan

The alternative development plan for major infrastructure and resources to meet Manitoba requirements without a new interconnection and without the WPS or MP sales is as follows:

- Conawapa with a 2021/22 ISD.
- A Combined Cycle Gas Turbine (400 MW) with a 2033/34 ISD.
- The 375/500 MW Sale to NSP as described in the Term Sheet in effect.
- 300 MW of additional wind generation with a 2010/11 ISD.
- Wuskwatim with a 2011/12 ISD.
- Pointe du Bois rebuilt with a 2016/17 ISD.

Table 2a at the end of this document details the annual dependable energy supply and demand values of this plan. Table 2b details the annual winter peak capacity supply and demand values of this plan.

Assumptions Common to Both Development Plans

The following summarizes the characteristics of major infrastructure and additional supply initiatives common to both development plans:

New Hydro			
Wuskwatim	200 MW gross	200 MW net	
Keeyask	695 MW gross	630 MW net	
Conawapa	1485 MW gross	1300 MW net	
Supply-Side Enhancement Projects (SSE)			
Planned Additional:			
Kelsey Rerunnering	77 MW /	0 GW.h for 2012/13	
Winnipeg River Plants Rerunnering	30 MW /	30 GW.h	
HVDC Bipole III Line (West)	89 MW /	243 GW.h by 2017/18	
License Review and Continued Operation:			
Selkirk #1-2	132 MW /	953 GW.h	
Brandon #5 Licence Review	105 MW /	811 GW.h	to 2018/19
Pointe du Bois (rebuilt)	120 MW /	620 GW.h	2016/17 (total plant)
Demand Side Management Program (DSM)			
Planned additional (by Mar 2025)	269 MW /	1158 GW.h	

MANITOBA HYDRO 2010/11 POWER RESOURCE PLAN

Date: Sept. 24, 2010

The purpose of the 2010/11 Power Resource Plan is to provide a recommendation for the long-term power resource development plan which, similar to last year, includes:

- a recommended development plan for use in the 2010 Integrated Financial Forecast and the Capital Expenditure Forecast, and
- an alternative development plan, which recognizes uncertainties in the recommended plan.

<u>2010/11 Recommended Power Resource Development Plan</u>

The recommended power resource development plan includes the major infrastructure and resources to pursue a new interconnection and facilitate the Wisconsin Public Service (WPS) and Minnesota Power (MP) Sales as follows:

- The 500 MW Sale to WPS and the 250 MW Sale to MP as described in the Term Sheets incorporating negotiated terms as at March 31, 2010,
- Keeyask with a 2019/20 In-Service Date (ISD),
- Conawapa with a 2023/24 ISD,
- A new interconnection capable of 1000 MW export and 750 MW import with a 2019/20 ISD,
- Additional north-south transmission beyond a 2000 MW Bipole III, as required for the combined Conawapa and Keeyask generation with a 2024/25 ISD.

<u>2010/11 Alternative Power Resource Development Plan</u>

The alternative power resource development plan for major infrastructure and resources to meet Manitoba requirements without a new interconnection and without the MP or WPS Sales is as follows:

- Conawapa with a 2022/23 ISD,
- Combined Cycle Gas Turbine with a 2033/34 ISD.

Inherent in these plans are the base resource assumptions, which can be found in Section 3. SUPPLY OF POWER.

The Supply and Demand Tables for Dependable Energy and Capacity can be found in Appendix A. Supply and Demand Tables for Average Energy can be found in Appendix B.

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Year	Debt Ratio (%)			Total Debt ($M)			Retained Earning ($M)			Total Debt Minus Retained Earnings ($M)		
	IFF 09-1	Alt. Dev. Scen.	Diff.	IFF 09-1	Alt. Dev. Scen.	Diff.	IFF 09-1	Alt. Dev. Scen.	Diff.	IFF 09-1	Alt. Dev. Scen.	Diff.
2009/10	74	74	Ø	9,956	9,956	Ø	2,183	2,183	Ø	7,773	7,773	Ø
2010/11	75	75	Ø	10,622	10,499	-23	2,261	2,262	+1	8,260	8,237	-23
2011/12	76	76	Ø	11,173	11,077	-96	2,331	2,332	+1	8,842	8,745	-97
2012/13	76	76	Ø	11,685	11,524	-161	2,403	2,388	-15	9,283	9,133	-150
2013/14	78	78	Ø	12,455	12,107	-348	2,538	2,456	-18	9,999	9,651	-348
2014/15	79	79	Ø	13,811	13,017	-794	2,641	2,511	-30	11,170	10,506	-664
2015/16	80	79	-1	15,456	13,823	-1,633	2,889	2,705	-184	12,567	11,118	-1,449
2016/17	80	79	-1	17,104	14,843	-2,261	3,153	2,927	-226	13,951	11,916	-2,035
2017/18	80	79	-1	18,081	15,783	-2,298	3,388	3,130	-258	14,693	12,653	-2,040
2018/19	80	79	-1	19,015	15,950	-3,065	3,632	3,298	-334	15,483	12,652	-2,831
2019/20	80	78	-2	19,661	16,254	-3,407	3,908	3,544	-464	15,753	12,710	-3,043
2020/21	79	77	-2	20,421	16,746	-3,675	4,207	3,845	-362	16,214	12,901	-3,313
2021/22	78	75	-3	20,314	16,460	-3,854	4,645	4,314	-331	15,669	12,146	-3,523
2022/23	76	72	-4	20,994	16,514	-4,480	5,190	4,904	-294	15,804	11,610	-4,194
2023/24	74	69	-5	21,036	16,555	-4,491	5,922	5,489	-433	15,114	11,066	-4,048
2024/25	70	65	-5	21,080	16,599	-4,481	6,713	6,133	-580	14,367	10,466	-3,901
2025/26	66	61	-5	20,524	16,048	-4,476	7,623	6,855	-768	12,901	9,193	-3,718
2026/27	62	57	-5	20,576	16,095	-4,481	8,629	7,666	-963	11,947	8,429	-3,518
2027/28	57	52	-5	20,633	16,151	-4,482	9,745	8,568	-1,177	10,888	7,583	-3,305
2028/29	51	46	-5	20,634	16,151	-4,483	10,969	9,578	-1,341	9,665	6,573	-3,092
2029/30		40			15,950			10,642			5,308	

Table 2a - Alternative Development Plan

System Firm Energy Demand and Dependable Resources (GW.h)
2009 Base Load Forecast

Fiscal Year	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Power Resources																		
Manitoba Hydro Plants																		
Existing	21110	21090	21080	21060	21040	21030	20920	20900	20880	20870	20850	20840	20830	20820	20820	20810	20560	20560
Wuskwatim			550	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250
Conawapa (net addition)													2151	4550	4550	4550	4550	4550
Keeyask (net addition)																		
Bipole III HVDC LINE									243	243	243	243	243	228	228	228	228	228
Manitoba Thermal Plants																		
Brandon Unit 5 (Drought Operation)	811	811	811	811	811	811	811	811	811	811								
Selkirk	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
Brandon Units 6-7 SCCT	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354
New Thermal																		
CCGT																		
SCGT																		
Wind Power: 400 MW	320	818	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254
Demand Side Management	244	440	606	719	819	842	798	825	890	949	993	1037	1082	1115	1151	1158	1133	1100
Major Rerunnering (incremental to existing)																		
Kelsey Rerunnering																		
Pointe du Bois Redeveloped								60	150	150	150	150	150	150	150	150	150	150
Imports																		
Total	2796	2796	2796	2796	2705	2705	2410	2414	2414	2414	2414	2414	2414	2414	2414	2414	1713	1575
TOTAL POWER RESOURCES	28588	29262	30404	31197	31186	31199	30750	30821	31198	31247	30461	30494	32680	35088	35124	35122	34145	33974
Demand																		
2009 Base Load Forecast	24239	24759	25323	25763	26177	26783	27137	27495	27808	28088	28452	28818	29185	29555	29927	30300	30681	31063
Non-Committed Construction Power			10	20	40	45	55	60	60	55	80	100	90	30	5			
Exports																		
Total	3626	3404	3385	3259	3156	3156	1560	1352	1352	1352	1352	1352	1642	1642	1642	1642	145	145
Total Demand	27865	28163	28718	29042	29373	29984	28752	28907	29220	29495	29884	30270	30917	31227	31574	31942	30826	31208
SURPLUS (w/ B#5)	723	1099	1686	2155	1813	1216	1998	1914	1978	1752	577	224	1763	3860	3550	3179	3320	2766
EXPORTABLE SURPLUS		288	875	1344	1002	405	1187	1103	1167	941	577	224	1763	3860	3550	3179	3320	2766

numbers are rounded to the nearest whole number

Table 2b - Alternative Development Plan

System Firm Capacity (Winter Peak) Demand and Resources (MW)

2009 Base Load Forecast

Fiscal Year	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Power Resources																		
Manitoba Hydro Plants																		
Existing	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900
Wuskwatim			200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Conawapa (net addition)																		
Keeyask (net addition)													520	1040	1300	1300	1300	1300
Bipole III HVDC LINE									89	89	89	89	89	48	48	48	48	48
Manitoba Thermal Plants																		
Brandon Unit 5 (Drought Operation)	105	105	105	105	105	105	105	105	105	105								
Selkirk	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
Brandon Units 6-7 SCCT	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298
New Thermal																		
CCGT																		
SCGT																		
Wind Power: 400 MW																		
(Wind has no dependable capacity for Winter Peak)																		
Demand Side Management	39	88	129	159	181	185	188	193	206	218	228	238	247	256	265	269	261	249
Major Rerunnering (incremental to existing)																		
Kelsey Rerunnering		11	34	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77
Pointe du Bois Redeveloped								43	43	43	43	43	43	43	43	43	43	43
Imports																		
Total	616	616	616	616	550	550	385	385	385	385	385	385	385	385	385	385		
TOTAL POWER RESOURCES	6090	6150	6414	6487	6443	6447	6285	6333	6435	6447	6352	6362	6891	7379	7647	7651	7259	7247
Demand																		
2009 Base Load Forecast	4363	4437	4530	4601	4664	4765	4820	4876	4924	4973	5038	5103	5168	5233	5299	5365	5432	5500
Non-Committed Construction Power																		
Exports																		
Total	693	638	638	605	605	605	413	413	413	413	413	413	550	550	550	550		
Total Demand	5056	5075	5168	5206	5269	5370	5232	5288	5336	5386	5450	5515	5718	5783	5849	5915	5432	5500
Reserve	445	448	454	459	472	483	510	516	520	524	531	538	544	551	558	565	621	630
TOTAL PEAK DEMAND	5501	5522	5622	5665	5741	5853	5742	5804	5856	5910	5981	6053	6262	6334	6407	6480	6053	6130
SURPLUS (w/ B#5)	589	627	792	823	702	594	543	528	579	537	371	309	630	1045	1241	1171	1206	1117
EXPORTABLE SURPLUS	484	522	687	718	597	489	438	423	474	432	371	309	630	1045	1241	1171	1206	1117

numbers are rounded to the nearest whole number

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GRA 2009/10

APPENDIX 15

20 Year Financial Outlook
Alternative Scenarios

Alternative Development Sequence

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
ALTERNATIVE DEVELOPMENT SEQUENCE
(In Millions of Dollars)

For the year ended March 31	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
REVENUES											
General Consumers											
at approved rates	1,160	1,159	1,177	1,191	1,204	1,229	1,244	1,260	1,272	1,283	1,297
additional *	-	33	69	113	161	212	266	322	381	442	508
Extraprovincial	414	383	554	583	616	593	703	736	748	751	740
Other	7	7	8	8	8	8	8	9	9	9	9
	1,581	1,584	1,808	1,896	1,988	2,042	2,222	2,326	2,409	2,485	2,554
EXPENSES											
Operating and Administrative	372	380	403	411	420	428	437	445	467	476	486
Finance Expense	417	412	468	533	550	571	558	572	611	667	633
Depreciation and Amortization	368	386	407	445	483	503	513	517	537	562	563
Water Rentals and Assessments	120	110	111	113	114	114	115	116	115	115	115
Fuel and Power Purchased	103	132	248	250	260	269	297	337	353	369	380
Capital and Other Taxes	73	76	76	79	83	88	92	97	102	106	109
Corporate Allocation	8	9	9	9	9	9	9	9	9	9	9
	1,460	1,504	1,723	1,840	1,919	1,982	2,020	2,094	2,195	2,303	2,294
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	121	79	87	56	68	56	194	222	202	168	246
*Additional General Consumers Revenue											
Percent Increase		2.90%	2.90%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Cumulative Percent Increase		2.90%	5.88%	9.59%	13.43%	17.40%	21.50%	25.76%	30.16%	34.71%	39.43%
Financial Ratios											
Debt	74%	75%	76%	76%	78%	79%	79%	79%	79%	78%	78%
Interest Coverage	1.24	1.15	1.14	1.09	1.10	1.08	1.25	1.27	1.23	1.19	1.27
Capital Coverage (excl Major Gen.)	1.37	1.10	1.14	1.30	1.21	1.47	1.83	1.84	1.96	2.06	2.59

Alternative Development Sequence

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
ALTERNATIVE DEVELOPMENT SEQUENCE
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
REVENUES											
General Consumers											
at approved rates	1,312	1,327	1,342	1,357	1,374	1,393	1,413	1,433	1,450	1,469	1,488
additional *	550	594	639	687	736	789	844	901	959	972	985
Extraprovincial	737	933	1,199	1,292	1,287	1,256	1,261	1,262	1,265	1,265	1,264
Other	9	9	10	10	10	10	10	11	11	11	11
	2,608	2,863	3,190	3,346	3,408	3,448	3,528	3,606	3,685	3,717	3,748
EXPENSES											
Operating and Administrative	495	512	523	533	544	554	566	576	588	600	612
Finance Expense	601	653	800	895	864	829	806	761	716	660	600
Depreciation and Amortization	558	589	653	694	705	720	737	731	713	720	729
Water Rentals and Assessments	116	124	137	140	140	141	141	142	142	143	144
Fuel and Power Purchased	399	374	344	356	364	332	313	338	355	367	378
Capital and Other Taxes	113	116	118	118	119	119	120	120	121	122	124
Corporate Allocation	9	9	9	9	9	9	9	9	9	9	9
	2,292	2,377	2,583	2,744	2,744	2,704	2,692	2,677	2,644	2,621	2,595
Non-controlling Interest	(15)	(17)	(18)	(18)	(19)	(23)	(25)	(28)	(30)	(33)	(36)
Net Income	301	469	590	585	644	722	811	901	1,011	1,064	1,116
*Additional General Consumers Revenue											
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	0.00%	0.00%
Cumulative Percent Increase	42.22%	45.06%	47.96%	50.92%	53.94%	57.02%	60.16%	63.36%	66.63%	66.63%	66.63%
Financial Ratios											
Debt	77%	75%	72%	69%	65%	61%	57%	52%	46%	40%	35%
Interest Coverage	1.32	1.49	1.62	1.63	1.72	1.84	1.98	2.15	2.36	2.54	2.75
Capital Coverage (excl Major Gen.)	2.21	2.29	2.43	2.32	2.21	2.44	2.58	2.77	2.76	2.70	3.27

Alternative Development Sequence

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
ALTERNATIVE DEVELOPMENT SEQUENCE
(In Millions of Dollars)

For the year ended March 31	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
ASSETS											
Plant in Service	12,527	13,034	15,075	15,566	15,982	16,691	17,127	17,837	20,301	20,646	21,010
Accumulated Depreciation	(4,663)	(5,018)	(5,398)	(5,805)	(6,216)	(6,649)	(7,091)	(7,540)	(8,010)	(8,507)	(9,007)
Net Plant in Service	7,865	8,015	9,677	9,761	9,765	10,042	10,035	10,297	12,292	12,139	12,003
Construction in Progress	1,950	2,439	1,249	1,108	1,966	2,535	3,313	4,070	3,013	3,762	4,398
Current and Other Assets	2,764	2,732	2,868	3,460	3,160	3,256	3,449	3,650	3,843	3,579	3,628
Goodwill	42	42	42	42	42	42	42	42	42	42	42
	12,621	13,228	13,836	14,370	14,933	15,874	16,840	18,059	19,190	19,522	20,072
LIABILITIES AND EQUITY											
Long-Term Debt	7,800	8,596	8,854	8,569	9,949	10,705	11,523	12,212	12,746	13,429	13,747
Current and Other Liabilities	2,156	1,903	2,223	2,955	2,158	2,312	2,300	2,631	3,037	2,521	2,507
Contributions in Aid of Construction	290	288	284	280	276	275	274	273	272	271	271
Retained Earnings	2,183	2,262	2,332	2,388	2,456	2,511	2,705	2,927	3,130	3,298	3,544
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,621	13,228	13,836	14,370	14,933	15,874	16,840	18,059	19,190	19,522	20,072

Alternative Development Sequence

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
ALTERNATIVE DEVELOPMENT SEQUENCE
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
ASSETS											
Plant in Service	21,467	24,969	27,793	28,946	29,585	30,372	30,949	31,661	32,246	32,852	33,561
Accumulated Depreciation	(9,505)	(10,036)	(10,635)	(11,276)	(11,933)	(12,608)	(13,300)	(13,998)	(14,706)	(15,422)	(16,148)
Net Plant in Service	11,961	14,933	17,158	17,670	17,652	17,764	17,648	17,663	17,540	17,430	17,412
Construction in Progress	5,222	2,869	846	288	306	155	243	240	373	526	693
Current and Other Assets	3,639	3,203	3,644	4,318	5,008	5,214	6,107	7,056	8,061	8,887	9,934
Goodwill	42	42	42	42	42	42	42	42	42	42	42
	20,865	21,047	21,691	22,318	23,008	23,174	24,040	25,001	26,017	26,885	28,081
LIABILITIES AND EQUITY											
Long-Term Debt	13,806	14,038	14,240	14,242	13,644	13,647	13,649	13,591	13,343	13,345	13,335
Current and Other Liabilities	2,940	2,422	2,274	2,313	2,955	2,396	2,446	2,560	2,808	2,605	2,690
Contributions in Aid of Construction	272	272	273	274	276	277	280	283	287	292	298
Retained Earnings	3,845	4,314	4,904	5,489	6,133	6,855	7,666	8,568	9,578	10,642	11,758
Accumulated Other Comprehensive Income	2	1	(0)	0	0	0	0	0	0	0	0
	20,865	21,047	21,691	22,318	23,008	23,174	24,040	25,001	26,017	26,885	28,081

Alternative Development Sequence

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
ALTERNATIVE DEVELOPMENT SEQUENCE
(In Millions of Dollars)

For the year ended March 31	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
OPERATING ACTIVITIES											
Cash Receipts from Customers	1,581	1,584	1,808	1,896	1,988	2,042	2,222	2,326	2,409	2,485	2,554
Cash Paid to Suppliers and Employees	(646)	(690)	(827)	(844)	(870)	(894)	(938)	(995)	(1,037)	(1,066)	(1,093)
Interest Paid	(452)	(423)	(482)	(547)	(575)	(579)	(590)	(600)	(663)	(724)	(674)
Interest Received	29	22	14	16	14	4	15	26	36	39	33
	512	493	513	520	558	573	709	758	746	734	821
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	745	800	400	540	1,400	1,000	1,000	1,200	1,400	1,000	600
Sinking Fund Withdrawals	262	227	27	102	482	-	0	-	-	456	171
Retirement of Long-Term Debt	(355)	(304)	(27)	(121)	(849)	(100)	(262)	(201)	(530)	(869)	(321)
Other	(32)	(10)	19	(12)	(14)	(12)	(13)	(14)	(14)	(26)	(15)
	621	713	419	509	1,019	888	725	985	855	561	435
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of cont	(1,115)	(1,057)	(931)	(921)	(1,292)	(1,286)	(1,220)	(1,470)	(1,408)	(1,092)	(994)
Sinking Fund Payment	(94)	(99)	(98)	(116)	(176)	(104)	(201)	(159)	(242)	(200)	(228)
Other	(36)	(20)	(16)	(17)	(15)	(31)	(29)	(40)	(28)	(27)	(27)
	(1,246)	(1,176)	(1,045)	(1,054)	(1,482)	(1,422)	(1,450)	(1,669)	(1,677)	(1,319)	(1,249)
Net Increase (Decrease) in Cash	(114)	30	(113)	(25)	94	40	(15)	74	(76)	(24)	8
Cash at Beginning of Year	66	(47)	(18)	(131)	(156)	(62)	(22)	(37)	37	(39)	(63)
Cash at End of Year	(47)	(18)	(131)	(156)	(62)	(22)	(37)	37	(39)	(63)	(55)

Alternative Development Sequence

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
ALTERNATIVE DEVELOPMENT SEQUENCE
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
OPERATING ACTIVITIES											
Cash Receipts from Customers	2,608	2,863	3,190	3,346	3,408	3,448	3,528	3,606	3,685	3,717	3,748
Cash Paid to Suppliers and Employees	(1,127)	(1,131)	(1,125)	(1,151)	(1,171)	(1,151)	(1,145)	(1,182)	(1,212)	(1,238)	(1,264)
Interest Paid	(644)	(690)	(818)	(915)	(893)	(867)	(834)	(797)	(759)	(705)	(619)
Interest Received	30	27	4	3	10	14	9	17	25	22	24
	867	1,069	1,251	1,283	1,355	1,444	1,559	1,645	1,738	1,796	1,888
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	800	400	200	-	-	-	-	-	-	-	-
Sinking Fund Withdrawals	285	741	171	-	-	316	-	-	60	250	-
Retirement of Long-Term Debt	(285)	(744)	(171)	-	-	(600)	-	-	(60)	(250)	30
Other	(14)	(17)	(13)	(14)	(14)	(14)	(16)	(16)	(17)	(30)	(59)
	786	380	187	(14)	(14)	(298)	(16)	(16)	(17)	(30)	(29)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of cont	(1,273)	(1,141)	(792)	(584)	(639)	(618)	(647)	(691)	(698)	(737)	(853)
Sinking Fund Payment	(263)	(318)	(178)	(142)	(147)	(152)	(139)	(144)	(149)	(152)	(145)
Other	(33)	(38)	(28)	(32)	(29)	(30)	(33)	(31)	(31)	(32)	(32)
	(1,569)	(1,497)	(998)	(757)	(816)	(800)	(819)	(866)	(879)	(920)	(1,030)
Net Increase (Decrease) in Cash	84	(48)	440	512	525	346	724	763	842	846	830
Cash at Beginning of Year	(55)	29	(19)	421	933	1,458	1,804	2,528	3,291	4,133	4,979
Cash at End of Year	29	(19)	421	933	1,458	1,804	2,528	3,291	4,133	4,979	5,809

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1.0 Overview

Capital Expenditure Forecast Summary

This Consolidated Capital Expenditure Forecast (CEF10) totals $16 931 million for the ten year period to 2019/20. Expenditures for Major New Generation & Transmission total $12 354 million, with the balance of $4 577 million comprised of expenditures for infrastructure renewal, system safety and security, new and increasing load requirements, and ongoing efficiency improvements.

Comparison to CEF09

The Capital Expenditure Forecast (CEF10) for the ten year period ending 2019/20 totals $16 931 million compared to $15 376 million for the same ten year period included in last year's Capital Expenditure Forecast (CEF09).

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year Total
CEF09	1 085	1 036	1 024	1 486	1 765	2 156	2 165	1 716	1 651	1 291	15 376
Incr (Decr)	37	33	108	(17)	(166)	(216)	(321)	514	660	923	1 555
CEF10	1 122	1 069	1 133	1 469	1 599	1 940	1 845	2 231	2 311	2 214	16 931

The increase of $1 555 million in capital expenditures over the ten year forecast period is comprised of the following:

	Total Projected Cost	Total Project Increase / (Decrease)	10 Year Increase (Decrease)
	($ Millions		
Keeyask Generating Station	$ 5 637	$ 1 045	$ 924
Conawapa Generating Station	7 771	1 446	(399)
Kelsey Improvements & Upgrades	302	112	111
Pointe du Bois Spillway Replacement	398	80	83
Kettle Improvements & Upgrades	166	90	70
Wuskwatim Generating Station	1 275	-	55
Pointe du Bois Safety Upgrades	50	50	50
System Refurbishment and Other Projects	NA	NA	328
Reduction to Target Adjustment	NA	NA	333
			$ 1 555

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PUB/MH I-56

Subject: Tab 6: Capital Expenditures
Reference: CEF 09-1, CEF 08-1, Order No. 116/08 (CEF 04-1 to CEF 07-1)

a) **Please confirm the accuracy of the progression of project costs, in the table that follows:**

Progression of Project Costs in $ M							
	CEF-03	CEF-04	CEF-05	CEF-06	CEF-07	CEF-08	CEF-09
Wuskwatim G.S.		846	935	1,094	1,275	1,275	1,275
Wuskwatim Transmission		199	200	257	320	316	316
Wuskwatim Total Project	988	1,045	1,135	1,351	1,595	1,591	1,591
Herblet Lake Transmission	57	55	54	54	95	93	93
Bipole III	360(E)	388(E)	1,880	1,880	2,248	2,248	2,248
Riel C.S.	96	101	103	103	105	268	268
Kelsey G.S.	121	121	166	166	184	190	190
Kettle G.S.		61	61	61	61	76	76
Pointe du Bois	421	288	692	834	818	818	318
Pointe du Bois Trans.					83	86	86
Slave Falls G.S.				179	192	198	198
Conawapa G.S.		4,050	4,516	4,978	4,978	4,978	6,325
Keeyask G.S.						3,700	4,592
500 KV Dorsey U.S. Border						205	205

ANSWER:

Confirmed with minor rounding differences.

PUB/MH I-56

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1, CEF 08-1, Order No. 116/08 (CEF 04-1 to CEF 07-1)**

d) Please provide a 20-year CEF 09-1.

ANSWER:

Please see Attachment 1.

ATTACHMENT 1

CAPITAL EXPENDITURE FORECAST FOR 20 YEAR OUTLOOK (2009/10 - 2028/29) - JANUARY 2010
(in millions of dollars)

	Total Project Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	20 Year Total
ELECTRIC																						
Major New Generation & Transmission																						
Wuskwatim - Generation	1,274.6	364.4	275.3	105.1	12.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	756.8
Wuskwatim - Transmission	316.3	90.1	30.5	18.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	139.5
Herblet Lake - The Pas 230 kV Transmission	93.2	41.9	30.4	7.2	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	81.5
Keeyask - Generation	4,591.6	67.7	85.0	195.3	198.6	182.3	485.5	799.1	808.3	584.7	537.5	263.9	74.9	-	-	-	-	-	-	-	-	4,282.8
Conawapa - Generation	6,324.8	60.4	60.4	75.0	111.8	190.1	231.5	308.2	290.3	513.6	846.1	881.7	905.0	833.8	632.2	240.7	7.0	-	-	-	-	6,168.0
Kelsey Improvements & Upgrades	189.6	45.1	6.8	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	52.5
Kettle Improvements & Upgrades	75.6	11.1	18.4	6.6	20.1	18.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.8
Pointe du Bois Improvements & Upgrades	318.0	13.8	14.8	15.5	53.0	83.1	110.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	290.9
Pointe du Bois - Transmission	85.9	9.0	26.3	10.4	20.6	13.9	3.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	83.2
Bipole 3	2,247.8	16.6	21.4	36.7	113.4	266.5	420.2	627.7	557.9	159.9	-	-	-	-	-	-	-	-	-	-	-	2,220.4
Riel 230/500 kV Station	267.5	36.1	58.4	79.6	45.1	38.2	4.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	262.0
Firm Import Upgrades	4.8	0.6	2.1	2.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8
Dorsey - US Border New 500 kV Transmission Line	204.8	-	0.5	1.9	8.2	17.6	32.4	79.3	64.8	-	-	-	-	-	-	-	-	-	-	-	-	204.8
Brandon Combustion Turbine Pipeline Upgrade	5.4	5.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.4
Demand Side Management	NA	40.3	43.0	42.5	38.4	33.9	29.9	29.0	27.1	25.6	25.1	21.8	21.6	21.5	21.4	20.6	16.0	16.3	16.6	17.0	17.3	524.9
Planning Study Costs	NA	5.7	8.0	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.6
Generating Station Improvements & Upgrades	NA	-	-	-	-	-	-	-	-	-	-	-	45.0	32.2	21.1	9.4	14.4	15.2	25.8	79.3	56.6	299.1
Additional North South Transmission	345.0	-	-	-	-	-	-	-	-	-	-	-	-	-	345.0	-	-	-	-	-	-	345.0
		808.1	681.5	599.4	623.1	844.1	1,318.0	1,843.4	1,748.4	1,283.6	1,408.7	1,167.4	1,046.5	887.6	1,019.7	270.7	37.4	31.5	42.4	95.3	73.9	15,831.9
New Head Office																						
New Head Office	278.1	14.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14.8
Corporate Relations																						
Waterways Management Program	NA	5.3	5.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.7

ATTACHMENT 1

CAPITAL EXPENDITURE FORECAST FOR 20 YEAR OUTLOOK (2009/10 - 2028/29) - JANUARY 2010

(in millions of dollars)

	Total Project Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	20 Year Total
Power Supply																						
Converter Transformer Bushing Replacement	5.9	0.1	0.4	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.3
Bipole 1 & 2 Electrode Line Monitoring	1.7	0.0	0.0	1.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.6
Dorsey Synchronous Condenser Refurbishment	32.3	3.0	2.5	3.6	2.5	2.6	2.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17.0
HVDC Bipole 1 Roof Replacement	5.9	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7
HVDC System Transformer & Reactor Fire Protection & Prevention	10.4	0.3	1.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9
HVDC AC Filter PCB Capacitor Replacement	34.5	2.4	6.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3
HVDC Transformer Replacement Program	NA	1.0	1.1	7.3	5.3	1.1	-	-	-	-	-	-	0.5	4.6	6.4	32.9	6.7	7.0	50.3	22.5	77.8	224.6
Dorsey 230 kV Relay Building Upgrade	73.8	1.1	1.9	4.0	18.4	32.1	12.0	4.9	-	-	-	-	-	-	-	-	-	-	-	-	-	72.5
HVDC Stations Ground Grid Refurbishment	4.3	0.6	0.5	0.6	0.6	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.3
HVDC Bipole 2 230 kV HLR Circuit Breaker Replacement	9.4	2.7	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1
HVDC Bipole 1 Pole Differential Protection	3.3	-	1.0	2.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.3
HVDC Bipole 1 By-Pass Vacuum Switch Removal	20.4	0.5	4.6	8.2	5.6	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.1
HVDC Bipole 2 Refrigerant Condenser Replacement	11.0	-	-	2.8	7.2	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.0
HVDC Bipole 1 Smoothing Reactor Replacement	31.8	0.0	0.1	0.1	0.1	4.0	18.0	7.2	2.5	-	-	-	-	-	-	-	-	-	-	-	-	31.8
HVDC Bipole 1 Converter Station, P1 & P2 Battery Bank Separation	3.2	-	0.0	1.0	2.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2
HVDC Bipole 1 DCCT Transductor Replacement	11.7	-	0.6	2.8	0.8	3.9	1.1	2.3	0.1	-	-	-	-	-	-	-	-	-	-	-	-	11.7
HVDC BP1 & BP2 DC Converter Transformer Bushing Replacements	8.7	-	-	0.5	1.0	1.7	5.2	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	8.7
HVDC Bipole 2 Valve Hall Wall Bushing Replacements	19.2	-	0.1	3.3	4.5	4.6	4.7	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	19.2
HVDC Bipole 1 CQ Disconnect Replacement	5.2	-	0.0	1.1	1.5	0.9	1.0	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2
HVDC Bipole 2 Thyristor Module Cooling Refurbishment	4.7	1.8	1.7	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.3
HVDC Bipole 2 Smoothing Reactor Replacement	17.1	0.8	3.5	3.2	5.7	3.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17.1
HVDC Bipole 1 Transformer Marshalling Kiosk Replacement	6.8	1.0	1.0	1.6	1.6	1.1	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.8
HVDC Bipole 2 Upgrades & Replacements	444.2	-	-	-	-	-	-	-	-	-	-	-	12.3	52.7	57.4	64.1	98.1	103.5	56.2	-	-	444.2
Pine Falls Rehabilitation	56.2	2.8	4.2	17.4	12.2	2.1	2.9	3.2	4.8	-	-	-	-	-	-	-	-	-	-	-	-	49.6
Jenpeg Unit Overhauls	115.9	-	-	-	-	-	-	2.3	2.6	18.6	24.5	25.1	25.6	17.2	-	-	-	-	-	-	-	115.9
Power Supply Dam Safety Upgrades	34.0	9.7	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.4
Winnipeg River Riverbank Protection Program	19.7	1.3	1.2	1.2	1.3	1.3	1.3	1.3	1.5	-	-	-	-	-	-	-	-	-	-	-	-	10.4
Power Supply Hydraulic Controls	16.0	3.1	1.9	1.2	-	-	-	-	-	2.2	2.7	0.7	-	-	-	-	-	-	-	-	-	11.7
Slave Falls Rehabilitation	198.3	13.0	4.0	1.1	16.3	11.8	15.6	54.3	59.4	11.8	-	-	-	-	-	-	-	-	-	-	-	187.3
Great Falls Unit 4 Overhaul	19.7	3.0	7.0	7.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17.8
Great Falls 115 kV Indoor Station Safety Improvements	11.6	1.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.6
Generation South Transformer Refurbish & Spares	21.0	0.0	1.5	3.1	5.3	4.4	2.8	2.7	1.1	-	-	-	-	-	-	-	-	-	-	-	-	20.9
Generation South Overhauls & Improvements	384.8	-	-	-	-	-	-	-	-	-	-	-	4.7	10.2	40.3	29.4	48.6	28.5	33.3	82.8	53.3	331.1
Water Licenses & Renewals	40.8	4.4	6.0	6.0	5.7	5.9	4.9	3.2	-	-	-	-	-	-	-	-	-	-	-	-	-	36.1
Generation South PCB Regulation Compliance	4.7	0.2	0.3	0.1	0.1	0.2	3.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.7
Kettle Transformer Overhaul Program	35.6	1.6	6.6	6.5	6.6	6.8	7.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.4
Generation South Breaker Replacements	9.4	1.6	3.1	2.2	2.0	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.3
Seven Sisters Upgrades	9.5	1.8	5.3	1.2	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.4
Generation South Excitation Upgrades	32.3	-	2.0	1.0	1.1	1.7	1.4	1.3	1.5	0.6	7.7	0.0	4.4	5.0	3.4	1.2	-	-	-	-	-	32.3
Brandon Unit 5 License Review	18.7	0.3	2.5	11.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.9
Selkirk Enhancements	14.2	5.8	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.0
Laurie River/CRD Communications and Annunciation Upgrades	4.8	0.2	3.5	0.0	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8
Notigi Marine Vessel Replacement & Infrastructure Improvements	2.6	0.0	1.3	1.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6
Fire Protection Projects - HVDC	5.2	0.5	0.4	1.6	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.2
Halon Replacement Project	42.5	14.6	13.1	9.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	36.8
Power Supply Fall Protection Program	13.5	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.2
Oil Containment - Power Supply	19.1	0.6	0.4	1.0	0.5	0.3	0.3	0.1	0.9	-	-	-	-	-	-	-	-	-	-	-	-	4.1
Grand Rapids Townsite House Renovations	5.2	0.1	0.4	0.9	1.2	1.3	1.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2
Grand Rapids Fish Hatchery	2.2	0.1	1.1	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.2
Generation Townsite Infrastructure	52.1	7.8	8.4	5.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21.6
Site Remediation of Contaminated Corporate Facilities	34.7	2.3	1.2	1.1	1.1	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.9
High Voltage Test Facility	26.9	10.6	13.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24.1
Power Supply Security Installations / Upgrades	43.2	9.7	16.0	8.7	2.1	1.5	1.0	1.0	0.5	-	-	-	-	-	-	-	-	-	-	-	-	40.6
Power Supply Sewer & Domestic Water System Install and Upgrade	15.1	7.3	3.4	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.4
Power Supply Domestic	NA	19.1	19.3	19.7	20.1	20.5	20.9	21.4	21.8	22.2	22.7	23.1	23.6	24.1	24.5	25.0	25.5	26.0	26.6	27.1	27.6	460.9
		139.5	161.4	157.2	134.6	116.4	108.9	108.1	96.5	55.5	57.5	48.9	71.0	113.7	132.0	152.6	178.9	165.0	166.4	132.4	158.7	2,455.4

ATTACHMENT 1

CAPITAL EXPENDITURE FORECAST FOR 20 YEAR OUTLOOK (2009/10 - 2028/29) - JANUARY 2010

(in millions of dollars)

	Total Project Cost	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	20 Year Total
Transmission																						
Winnipeg - Brandon Transmission System Improvements	40.0	3.1	1.6	3.4	3.6	5.0	21.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38.4
Transcona East 230-66 kV Station	31.0	1.1	11.0	13.2	5.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.5
Neepawa 230 - 66 kV Station	30.0	1.1	14.1	9.5	5.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9
Pine Falls - Bloodvein 115 kV Transmission Line	34.1	-	0.3	0.9	4.4	20.6	7.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34.1
Transmission Line Re-Rating	24.1	3.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2
St Vital-Steinbach 230 kV Transmission	32.2	-	-	-	-	-	-	0.8	0.9	2.6	6.0	9.6	12.3	-	-	-	-	-	-	-	-	32.2
Rosser Station 230 - 115 kV Bank 3 Replacement	5.8	2.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6
Rosser - Inkster 115 kV Transmission	5.1	3.3	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.7
Transcona Station 66 kV Breaker Replacement	6.0	0.0	3.6	1.8	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.0
Transcona & Ridgeway Stations 66 kV Bus Upgrades	2.8	1.7	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4
Dorsey 500 kV R502 Breaker Replacement	2.6	2.3	0.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6
13.2kV Shunt Reactor Replacements	33.0	0.0	0.0	4.1	4.2	4.3	4.4	4.4	4.5	4.6	2.5	-	-	-	-	-	-	-	-	-	-	33.0
Birtle South-Rossburn 66 kV Line	4.9	-	-	-	-	0.1	0.3	4.5	-	-	-	-	-	-	-	-	-	-	-	-	-	4.9
Stanley Station 230-66 kV Transformer Addition	21.1	-	-	-	1.8	8.1	7.6	3.5	-	-	-	-	-	-	-	-	-	-	-	-	-	21.1
Stanley Station 230-66 kV Hot Standby Installation	6.2	4.9	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.1
Ashern Station 230 kV Shunt Reactor Replacement	2.7	0.0	0.0	-	2.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.7
Tadoule Lake DGS Tank Farm Upgrade	1.1	0.5	0.5	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.0
Interlake Digital Microwave Replacement	19.7	3.5	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.8
Communication System - Southern MB (Great Plains)	21.9	2.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4
Communications Upgrade Winnipeg Area	7.4	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7
Pilot Wire Replacement	9.6	1.3	1.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.7
Transmission Line Protection & Teleprotection Replacement	21.1	1.4	6.1	6.1	2.3	1.1	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17.9
Winnipeg Central Protection Wireline Replacement	9.3	2.5	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1
Mobile Radio System Modernization	30.7	0.3	2.5	9.2	10.6	8.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.6
Cyber Security Systems	10.1	3.6	0.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.0
Site Remediation	13.3	1.3	3.8	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.2
Oil Containment	7.4	0.9	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.4
Station Battery Bank Capacity & System Reliability Increase	46.5	5.3	4.7	6.4	6.4	6.6	6.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7
Red River Floodway Expansion Project	1.8	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3
Waverley Service Centre Oil Tank Farm Replacement	3.0	0.5	1.0	0.6	0.4	0.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0
115 kV Transmission Lines	NA	-	-	-	-	-	-	-	-	-	-	-	10.3	16.1	19.8	21.1	25.8	23.7	25.5	28.4	28.9	199.7
230 kV Transmission Lines	NA	-	-	-	-	-	-	-	-	-	-	-	5.9	9.2	11.3	12.1	14.8	13.6	14.6	16.3	16.5	114.3
Sub-Transmission	NA	-	-	-	-	-	-	-	-	-	-	-	4.3	6.7	8.3	8.8	10.8	9.9	10.6	11.9	12.1	83.4
Communications	NA	-	-	-	-	-	-	-	-	-	-	-	14.7	23.0	28.2	30.0	36.8	33.8	36.3	40.5	41.2	284.4
Site Remediation	NA	-	-	-	-	-	-	-	-	-	-	-	1.2	1.8	2.2	2.4	2.9	2.7	2.9	3.2	3.2	22.4
Transmission Domestic	NA	29.6	30.0	30.6	31.2	31.8	32.4	33.1	33.8	34.4	35.1	35.8	36.5	37.3	38.0	38.8	39.5	40.3	41.1	42.0	42.8	714.1
		77.5	86.0	86.9	78.3	86.2	81.4	46.4	39.2	41.6	43.6	45.4	85.1	94.1	107.8	113.2	130.7	124.1	131.1	142.2	144.7	1,785.4
Customer Service & Distribution																						
Winnipeg Distribution Infrastructure Requirements	14.9	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.7
Defective RINJ Cable Replacement	8.7	0.5	2.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1
Brereton Lake Station Area	9.0	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3
Stony Mountain New 115 - 12 kV Station	5.0	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7
Rover Substation Replace 4 kV Switchgear	12.7	0.4	3.3	3.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.5
Martin New Outdoor Station	28.2	1.0	14.5	9.1	2.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	27.0
Frobisher Station Upgrade	14.4	4.4	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.5
Burrows New 66 kV-12 kV Station	28.6	9.1	12.2	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26.3
Winnipeg Central District Oil Switch Project	7.1	1.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8
William New 66 kV-12 kV Station	10.3	0.5	3.6	3.1	2.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.0
Waverley West Sub Division Supply - Stage 1	6.5	4.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.4
St. James 24 kV System Refurbishment	65.9	1.3	14.1	31.6	18.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65.8
Shoal Lake New 33 - 12.47 kV DSC	3.6	3.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.2
York Station	4.0	2.0	1.8	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.9
Cromer North Station & Reston RE12-4 25 kV Conversion	4.3	3.0	0.1	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.3
Brandon Crocus Plains 115 - 25 kV Bank Addition	6.3	0.6	3.1	1.9	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.2
Winkler Market Feeder M25-13 Conversion	2.9	0.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.8
Neepawa North Feeder NN12-2 & Line 57 Rebuild	1.9	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9
Perimeter South Station Distribution Supply Centre Installation	2.4	0.4	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4
Niverville Station 66-12 kV Bank Replacements	2.6	2.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6
Winnipeg Central District Underground Network Asbestos Removal	3.0	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.7
Gas SCADA Replacement	4.6	1.0	3.0	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.6
Distribution		-	-	-	-	-	-	-	-	-	-	-	30.5	47.9	58.6	62.8	76.7	70.5	75.7	84.4	85.8	592.9
Customer Service & Distribution Domestic	NA	115.9	117.5	119.9	122.3	124.7	127.2	129.8	132.4	135.0	137.7	140.5	143.3	146.1	149.1	152.0	155.1	158.2	161.3	164.6	167.9	2,800.4
		158.1	177.8	176.3	147.0	124.7	127.2	129.8	132.4	135.0	137.7	140.5	173.8	194.0	207.8	214.7	231.8	228.7	237.0	249.0	253.6	3,576.9
Customer Care & Marketing																						
Advanced Metering Infrastructure	30.9	-	4.0	5.3	5.4	5.6	4.3	4.2	-	-	-	-	-	-	-	-	-	-	-	-	-	28.8
Customer Care & Marketing Domestic	NA	2.5	2.6	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0	3.1	3.1	3.2	3.3	3.3	3.4	3.5	3.5	3.6	3.7	61.1
		2.5	6.5	8.0	8.1	8.3	7.1	7.1	2.9	2.9	3.0	3.1	3.1	3.2	3.3	3.3	3.4	3.5	3.5	3.6	3.7	89.9
Finance & Administration																						
Corporate Buildings	NA	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	160.0
Workforce Management (Phase 1 to 4)	11.3	3.9	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.9
Fleet	NA	13.3	13.5	13.8	14.1	14.3	14.6	14.9	15.2	15.5	15.8	16.2	16.5	16.8	17.1	17.5	17.8	18.2	18.6	18.9	19.3	321.9
Finance & Administration Domestic	NA	24.1	24.4	24.9	25.4	25.9	26.4	27.0	27.5	28.1	28.6	29.2	29.8	30.4	31.0	31.6	32.2	32.9	33.5	34.2	34.9	582.0
		49.2	46.9	46.7	47.5	48.3	49.1	49.9	50.7	51.6	52.5	53.3	54.3	55.2	56.1	57.1	58.1	59.1	60.1	61.1	62.2	1,068.9
Capital Increase Provision		-	-	-	-	-	-	63.1	90.4	82.8	97.3	99.2	-	-	-	-	-	-	-	-	-	432.8
ELECTRIC CAPITAL SUBTOTAL		1,255.0	1,165.5	1,074.5	1,038.6	1,228.0	1,691.7	2,247.6	2,160.5	1,653.3	1,800.3	1,557.9	1,433.8	1,347.8	1,526.8	811.5	640.2	611.8	640.5	684.6	696.8	25,266.8

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PUB/MH I-4

Reference: **Risk Analysis, - Tab 8 & Appendix 12.5**

f) **Provide a project-specific NPV cost benefit analysis for the Bipole III comparing the east and west routing alternatives.**

ANSWER:

Project cost estimates for Bipole III east and west routing alternatives are provided in the table below.

Bipole III Summary

	West of Lake Winnipegosis	East of Lake Winnipeg
Estimated Line Length*	1341 km	885 km
Estimated Capital Cost **:		
Capital Cost of Converters	$1166 M	$1166 M
Capital Cost of Line	$1081 M	$671 M
Total	**$2247 M**	**$1837 M**
Estimated Cost of Increased Line Losses, West versus East *:**		
Existing Generation with Converters	$107 M	
With Conawapa and Converters	$181 M	

* Very rough estimate as broad corridor selection only at this time.

** Estimated capital costs are given in total in-service dollars including escalation and interest during construction. A 2017 in-service date is assumed.

*** Estimated costs of line losses reflect the present value over 40 years and are based on a forecast of export prices, historical loading patterns and corporately approved economic indices and forecasts. Costs of line losses are given in 2017 present value dollars.

MIPUG/MH I-10

Reference: **Major Projects**

b) **IFF06-3 notes at page two that it assumes that the Bipole III line along with 2000 MW of converter capability will be in service by 2017/18 and that the capital forecast includes an amount of $1.9 billion based on the assumption of a west-side routing. Please provide a copy of the Electric Operations Projected operating statement, balance sheet and cash flow statement assuming that Bipole III followed an east-side routing. Please discuss whether there would be any associated changes to the converter requirements with an east-side routing and include the impact of any associated converter station changes in the statements.**

ANSWER:

For the purposes of the Integrated Financial Forecast it has been assumed that the west route for Bipole III HVDC line is the route that will be developed. Manitoba Hydro is currently developing plans to proceed, with introductory consultations with regulatory authorities, aboriginal communities, and rural towns and municipalities with regard to the development of Bipole III running from the Nelson River via the area west of Lake Winnipegosis and on to the Riel Station site on the east side of Winnipeg.

The last Integrated Financial Forecast that assumed the East side route of Bipole III was IFF04-1. In IFF04-1, Bipole III line only was included at a cost of $388 million. A technical requirement of the west route, due to the inability to parallel Bipole III with the existing HVDC system, is that converter capability must be constructed at both the north and south location coincident with the new HVDC line. It is assumed that 2000MW of converter capability will be constructed for reliability.

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PUB/MH II-90

Subject: Tab 8: Energy Supply
Reference: PUB/MH I-60 Bipole III, 2007/12/07 PUB/MH I-4 (f)

a) Please confirm that Bipole III costs have evolved as follows:

	East Side	West Side	Potential West Side	Updated Alternative
Line Length	885 km	1,341 km	1,375 km	1,670 km
Line Cost	$671 M	$1,081 M	$1,108 M	$1,352 M
Cost/km	$0.76/M	$0.81/km	$0.81/M	$0.81/M
Capital Cost Increment	0	$410 M	$437 M	$681 M
Converter Costs - Unchanged at $1,166 M				
Line Losses 40-Year PV - $181 M				

ANSWER:

The costs for the East side and the West side above are consistent with Manitoba Hydro estimates. Manitoba Hydro has not identified a Potential West Side and an Updated Alternative or provided costs for such options and is therefore unable to confirm the data contained in the table.

PUB/MH II-90

Subject: **Tab 8: Energy Supply**
Reference: **PUB/MH I-60 Bipole III, 2007/12/07 PUB/MH I-4 (f)**

d) Please confirm that the East Side alternative would have had similar loads, but in the event of Bipole I and II failure could operate at a 3,000 MW level and transmit up to about 2,200 GWh of energy/month.

ANSWER:

The East Side Bipole III alternative would have had converters rated at 2,000 MW which is the same as the West Side Bipole III. However, in the event of an Interlake corridor loss, the East Side Bipole III alternative would be technically capable of paralleling operation at a 3,000 MW level - a capability the West Side Bipole III will not have.

Paralleling is the ability to place more than one set of converters on a single transmission line, greatly increasing the capacity of the line. The East Side Bipole III alternative is technically capable of being used for paralleling because its length is similar to that of the existing Bipole I and II lines. The West Side Bipole III can not have paralleling capability for technical reasons, and the new Bipole III converters will be specifically designed to work with the western routed line. Consequently, with an Interlake corridor loss, the transmission capacity for the West Side Bipole III is equal to that of the Bipole III converters or 2000 MW.

If in the event of loss of the Interlake corridor due to failure of Bipole I and II transmission lines, an East Side Bipole III paralleled with Bipole I and II converters could transfer up about 3000 MW of power south, assuming the necessary converter equipment would be available.

Theoretically, in a 31 day month, up to about 2,230 GWh of energy (before consideration of losses) could be transmitted with 3,000 MW of transfer capability, assuming continuous loading to the maximum transfer capability for the entire period. Such continuous loading to the maximum transfer capability is not the normal operating practice, does not allow for following the Manitoba load shape and does not allow for any maintenance work. The paralleling mode would only be used for minimum periods during unusual operating situations when the only other alternative would be to shed load.

30.

PUB/MH I-59

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1/CEF 08-1**

a) **Please provide the most recent budget estimates for the major components of Bipole III:**

   i. **Northern Converter**
   ii. **Transmission Lines**
   iii. **Southern Converter**

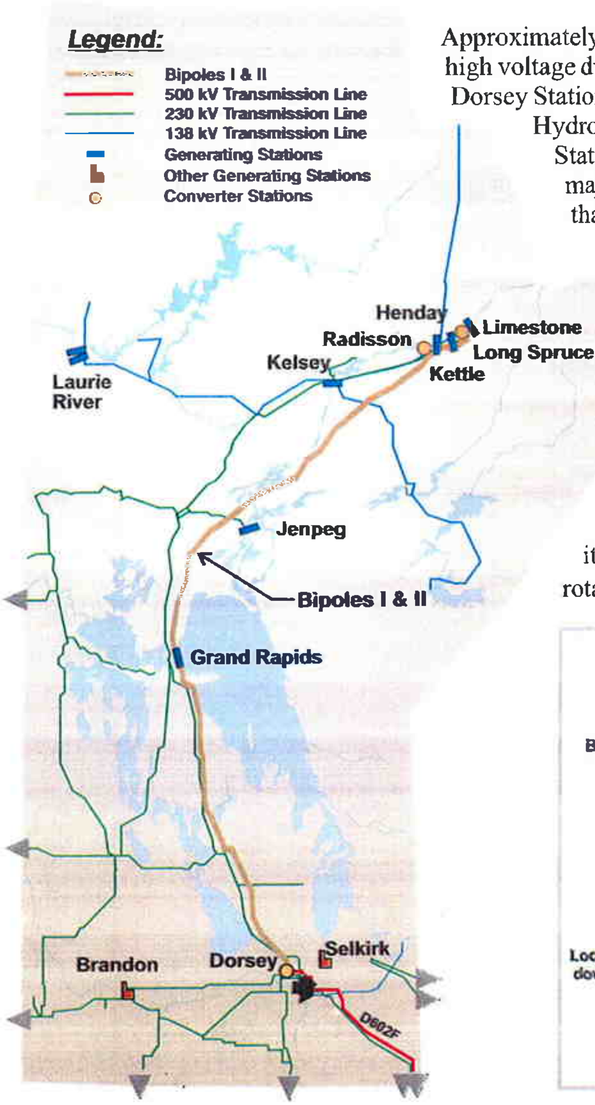
ANSWER:

Please see the following table for the major components of Bipole III.

COMPONENTS	**APPROVED BUDGET (IN THOUSANDS)**
Transmission Base Estimate	814,312
Escalation & Interest	319,336
Subtotal	1,133,648
Northern Converter Base Estimate	388,482
Southern Converter Base Estimate	485,116
Escalation & Interest - Converters	240,591
Subtotal	1,114,189
TOTAL	**2,247,837**

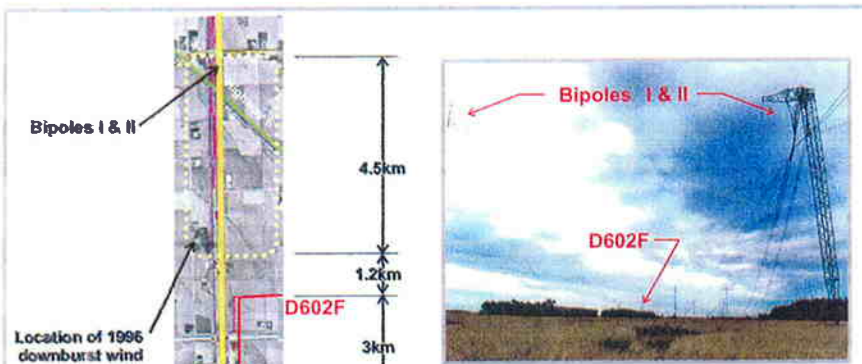
A Major Reliability Improvement Project

The Reliability Concern



Approximately 75% of Manitoba's generating capacity is delivered to southern Manitoba via the existing high voltage direct current (HVdc) Interlake corridor which is shared by Bipoles I & II which terminate at Dorsey Station, in the Rural Municipality (RM) of Rosser, northwest of the City of Winnipeg. Manitoba Hydro's system is vulnerable to the risk of outage of either the Interlake corridor or Dorsey Station, both of which could, for example, occur as a result of a severe weather incident such as a major ice storm, an extreme wind event or a tornado. System reliability studies have concluded that the likelihood of such events occurring when combined with the potential consequences of prolonged major outages warrant mitigation measures to reduce dependency on Dorsey Station and the existing HVdc Interlake corridor.

In 1996, the existing Bipoles I & II were concurrently lost as a result of an extreme wind event in the vicinity of Grosse Isle, north of Dorsey Station. The existing 500 kilovolt (kV) international transmission line (known as D602F), which runs from Dorsey Station to Forbes, Minnesota was used to import power to support the Winnipeg area transmission system. Had the wind event occurred a few kilometres further south, D602F would also have been damaged severely limiting the ability of the system to import power for Manitobans. Similarly, if Dorsey Station incurred a similar major outage (i.e., involving the HVdc lines and D602F), it would severely limit sources of major alternative energy supply which could result in rotating blackouts and supply restrictions.



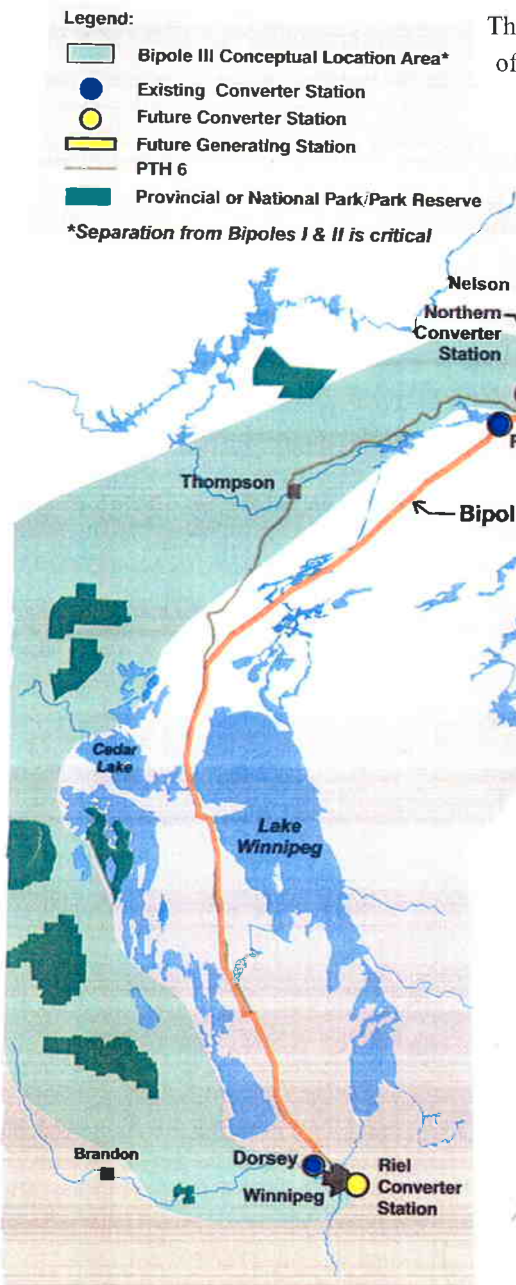
Sept. 5, 1996 Downburst Wind Event in which Bipoles I & II were lost

The Bipole III Project will improve system reliability in a number of ways. The project will establish a second converter station (Riel Station) in southern Manitoba which will provide a second major point of power injection into the system. As well, Bipole III will reduce risks from a range of possible system outages such as:

- The HVdc facilities at Dorsey Station
- The adjacent 500 kV station at Dorsey Station
- The Bipoles I & II Interlake corridor
- The corridor immediately north of Dorsey Station containing D602F, Bipoles I & II and a 230 kV line to Brandon
- The transmission corridors around Winnipeg

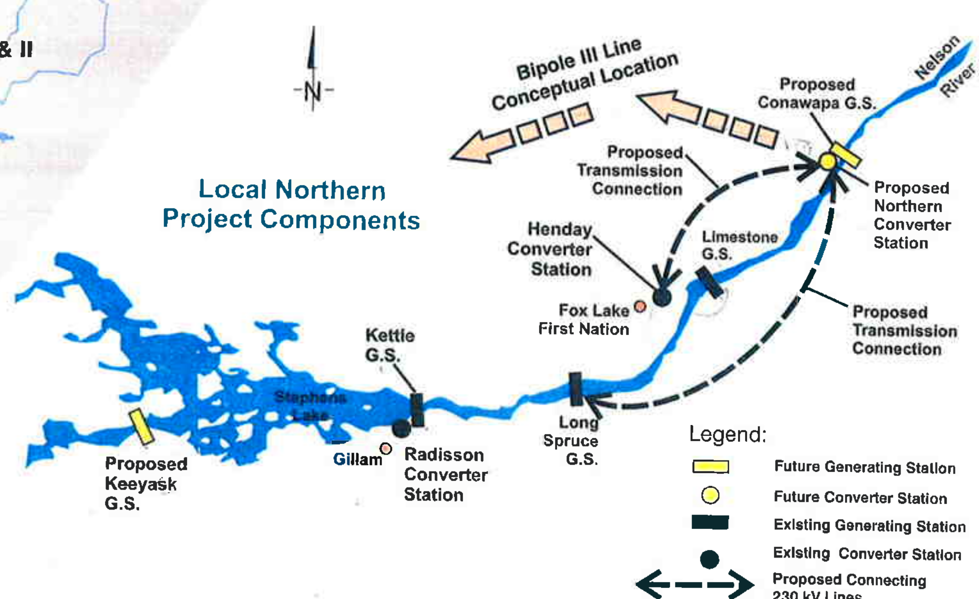
In addition, Bipole III will improve the existing Bipoles I & II line losses and provide additional transmission line capacity to get new northern hydroelectric generation to southern markets.

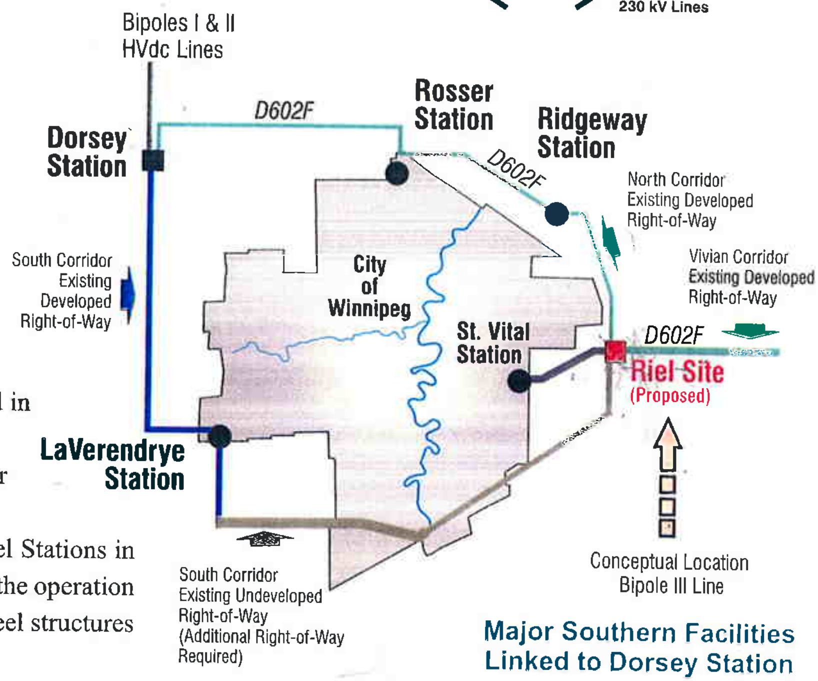
Bipole III Project Concept



There is a need to improve the reliability of the existing transmission system. Following an assessment of reliability options and pursuant to a review by the Manitoba Hydro Electric Board and the Province a decision was made to develop Bipole III in the westerly area of the Province. The in-service date for Bipole III is 2017.

Bipole III will originate at a new northern converter station site at the Conawapa Generating Station, will travel south and west of Lakes Winnipegosis and Manitoba and will come south of Winnipeg and terminate at the Riel site immediately east of the Red River Floodway in the RM of Springfield. The locations of the new northern converter station and Riel Station are identified on the accompanying map which also illustrates the general conceptual location area for eventual siting of alternative routes for Bipole III.





Following the introductory round of community/public consultation, the conceptual location area will be refined in order to define a specific project study area for the formal Site Selection and Environmental Assessment (SSEA) process which is to be initiated in the fall. Lines will be required from the new northern converter station at Conawapa to connect to the existing Henday Converter Station and Long Spruce Generating Station, in northern Manitoba.

A 500 kV transmission line will be required to link Dorsey and Riel Stations in southern Manitoba. A ground electrode facility will be required for the operation of each of the new converter stations. Bipole III will be strung on steel structures on a 60 meter wide right-of-way.

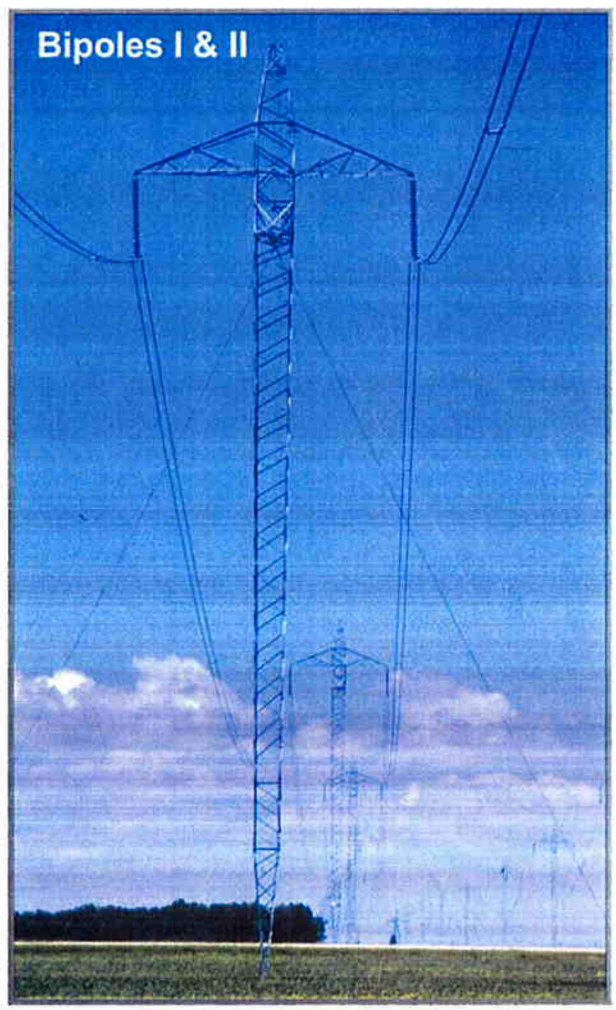
The Site Selection and Environmental Assessment (SSEA) Process

Identification of a proposed route for Bipole III will be based on a Site Selection and Environmental Assessment (SSEA) process. The SSEA process is a phased approach which will involve the systematic refinement of a project study area to identify and assess the best balanced choice for a proposed route. The SSEA iterative process includes the following:

- Defining a project study area based on factors including community and public input, environmental and technical (engineering) considerations
- Identifying regional and site-specific constraints and opportunities for transmission line routing including potentially sensitive socio-economic, cultural and biophysical features
- Identifying and evaluating alternative routes based on community/public input, local and Traditional Knowledge, socio-economic, biophysical, technical and cost considerations
- Selecting a preferred route which, where feasible, minimizes potential negative effects and enhances opportunities
- Developing impact management measures, where required, to address potential negative effects

Ongoing community/public input is a critical component of the SSEA process. A description of the planned community/public consultation program for Bipole III is provided in the next section of this newsletter.

The SSEA process will be documented in an Environmental Impact Statement (EIS) that will accompany Manitoba Hydro's application for environmental licensing. The SSEA process for Bipole III is scheduled to take four years to complete and the project EIS will be submitted to government regulatory authorities in the fall of 2011.



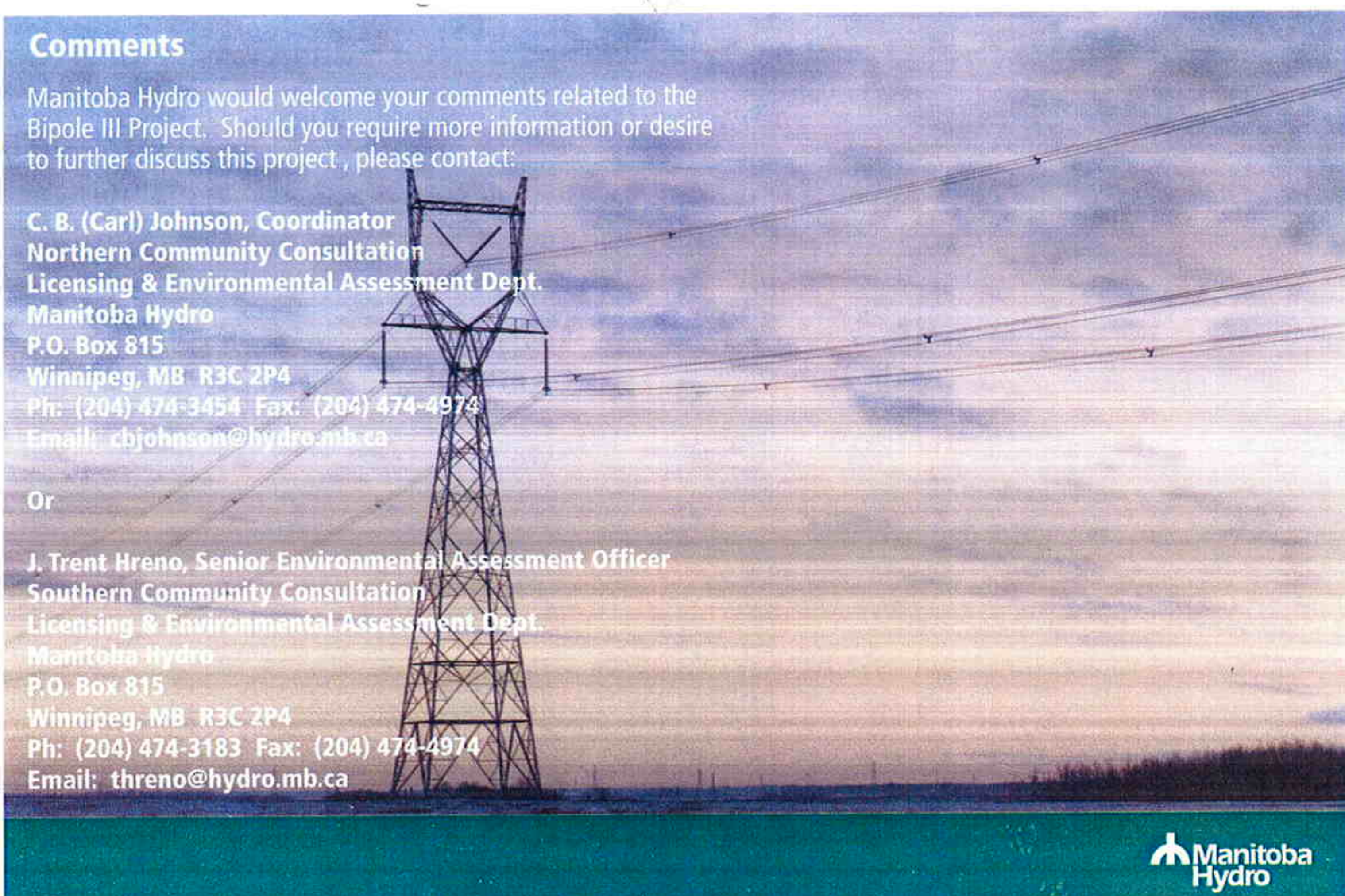
Community and Public Consultation

Consultation with communities, resource users, stakeholders and the public is a critical part of the planning process for identifying and evaluating alternative routes, and selecting a preferred route for Bipole III. The purpose is to facilitate community and public understanding about the project and the SSEA process, to enable information to be shared as it becomes available, and to be responsive to identified concerns. Information obtained will be incorporated into project planning to assist in identifying a proposed route and in assessing the potential impacts and mitigative measures associated with this choice.

Four rounds of community/public consultation are planned for Bipole III at key planning junctures of the SSEA process. Each round will include meetings with elected officials, community leadership, organizations and other potentially affected stakeholders, as well as Public Open Houses in the project region. In Aboriginal communities, formal consultation will begin following initial dialogue during the introductory round and the development of a consultation plan with potentially affected communities. Following the introductory round, a second round which will commence the formal SSEA for Bipole III is anticipated to begin in the fall of 2008. To ensure that activities are conducted in an efficient and timely manner, two teams of Manitoba Hydro representatives will concurrently carry out the ongoing community and public consultation process.

Regulatory Approvals

Development of Bipole III will require a Class 3 licence under ***The Environment Act*** (Manitoba). The environmental impact assessment for the project, including a program of community/public consultation, and identification of potential impacts and mitigative measures, will be documented in an Environmental Impact Statement (EIS). The project EIS, together with an Environment Act Proposal Form (EAPF) will be submitted to Manitoba Conservation as application for the Environment Act Licence. It is anticipated that Manitoba Conservation will coordinate with the Canadian Environmental Assessment Agency to ensure a harmonized approach to application of the Federal ***Canadian Environmental Assessment Act.***
Receipt of the Environment Act Licence is required in late 2012 to meet a project in-service date of 2017.



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PUB SUPPLEMENTAL TO PUB/MH II-194(a) – NET FIRM ENERGY FORECAST

MH's Response with PUB (in bold) addition of Aug 2010 GWh. totals and comparison of 2010 to 2009 GWh

	May/08 (GWh)	May/09 (GWh)	Difference (09 vs 08) (GWh)	**Aug/10 (GWh)**	**Difference 10 vs. 09 (GWh)**
2009/10	24,937	24,080	-857	--	--
2010/11	25,713	24,600	-1,113	**23,962**	**-638**
2011/12	26,362	25,159	-1,203	**24,579**	**-580**
2012/13	26,922	25,599	-1,323	**24,981**	**-618**
2013/14	27,241	26,012	-1,229	**25,647**	**-365**
2014/15	27,531	26,618	-913	**26,020**	**-598**
2015/16	27,827	26,973	-854	**26,438**	**-535**
2020/21	29,432	28,654	-778	**28,220**	**-434**
2025/26	31,108	30,516	-592	**30,109**	**-307**

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PUB/MH II-194

Reference: **20 IFF 09-1/PUB/MH I-209/ 2008/09 & 2007/08 Load Forecasts: Domestic Load**

a) Please confirm the following domestic load forecast history:

	Net Firm Energy Load Forecast		Difference (GWh)	Domestic Sales at Generation		
	2007/08 (GWh)	2008/09 (GWh)		IFF 08-1 Assumptions (GWh)	PUB/MH I-209 IFF 09 Assumptions (GWh)	IFF Difference (GWh)
2009/10	24,937	24,080	-857	24,875	23,968	-907
2010/11	25,713	24,600	-1,113	25,488	24,346	-1,142
2011/12	26,362	25,169	-1,193	26,050	24,718	-1,332
2012/13	26,922	25,599	-1,343	26,544	25,075	-1,469
2013/14	27,241	26,012	-1,229	26,787	25,413	-1,374
2014/15	27,531	26,618	-913	27,049	26,030	-1,019
2015/16	27,827	26,973	-854	27,296	26,439	-857
2020/21	29,432	28,654	-778	28,789	27,551	-1,238
2025/26	31,108	30,516	-592	30,324	29,379	-945

ANSWER:

The following table contains the correct figures and references, including:

- Correct references to the forecasts (i.e. the forecast figures provided are associated with the May 2008 (2008/09 - 2028/29) and the May 2009 (2009/10 - 2029/30) electric forecasts;
- The correct firm energy for the May 2009 forecast during 2011/12 is 25, 159; and
- The correct forecast difference for 2011/12 is -1,203 and the correct difference for 2012/13 is -1,323.

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The load forecast and IFF figures differ because the IFF excludes DSM impacts and includes several additional factors in domestic sales, such as station service and losses arising as a result of generation and transmission facilities.

	Net Firm Energy Load Forecast		**Difference (GWh)**	**Domestic Sales at Generation**		
	May 2008 (GWh)	**May 2009 (GWh)**		**IFF 08-1 Assumptions (GWh)**	**PUB/MH I-209 IFF 09 Assumptions (GWh)**	**IFF Difference (GWh)**
2009/10	24,937	24,080	-857	24,875	23,968	-907
2010/11	25,713	24,600	-1,113	25,488	24,346	-1,142
2011/12	26,362	25,159	-1,203	26,050	24,718	-1,332
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2015/16	27,827	26,973	-854	27,296	26,439	-857
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PUB/MH II-194

Reference: 20 IFF 09-1/PUB/MH I-209/ 2008/09 & 2007/08 Load Forecasts: Domestic Load

b) Please confirm that MH's annual domestic sales at generation are currently (IFF 09-1) forecast to be about 1,000 GWh lower than in IFF 08-1.

ANSWER:

Confirmed.

PUB/MH II-194

Reference: 20 IFF 09-1/PUB/MH I-209/ 2008/09 & 2007/08 Load Forecasts: Domestic Load

c) Please explain this apparent forecast reduction in 2009/10, 2010/11, and 2011/12 relative to:

- **Residential customers.**
- **Mass market.**
- **Top consumers.**

ANSWER:

The reductions in the Net Firm Energy Load Forecast for those three years were 857 GW.h, 1113 GW.h and 1203 GW.h. The reduction was a result of:

- The residential forecast was reduced 19 GW.h, 36 GW.h. and 69 GW.h.;
- The mass market forecast was reduced 73 GW.h., 102 GW.h and 110 GW.h.; and
- The top consumers group was reduced by 839 GW.h, 1024 GW.h and 1093 GW.h. The changes in the top consumer group was primarily due to forecast electric load reductions in the primary metals and chemical industries.

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PUB/MH II-194

Reference: 20 IFF 09-1/PUB/MH I-209/ 2008/09 & 2007/08 Load Forecasts: Domestic Load

d) Does the 1,000 GWh/year long-term cutback include the recent step back of about 500 GWh/year in the primary metal and pulp & paper industries?

ANSWER:

The recent step back in the primary metal industry was included. The step back in the pulp & paper industries occurred after the 2009/10 (May 2009) Electric Load Forecast was released and therefore was not included in the 2009/10 forecast.

General Service Top Consumers

This category includes the top energy consuming businesses in Manitoba and represents 40% of all electricity consumed in the General Service sector and 26% of all electricity Sales. The Top Consumers group includes 17 companies that account for 25 customers in Primary Metals, Chemicals, Petrol/Oil/Natural Gas, Pulp/Paper, Food/Beverage, Mining and Colleges/Universities. The Top Consumers category includes all future energy requirements for these customers. Some customers are planning major expansions, some customers are expected to remain at current operating levels and some customers are planning to reduce their levels of consumption in the future.

Each company in the Top Consumers group is forecast individually. Information on individual company operating plans is collected from industry news, Manitoba Hydro's economic experts and Manitoba Hydro's Key & Major Account representatives. This information is used to prepare company specific forecasts.

The Top Consumers are forecast individually because their usage does not grow in a slow, steady, predictable pattern. These types of load changes are not conducive to econometric forecasting models and must be examined on an individual basis. The forecast for each company includes their short term committed plans and expectations over the next several years.

This category contains some speculative load growth because new, large, Industrial customers could begin operating in the future. This classification is called Potential Large Industrial Loads (PLIL). At this time, the specifics of these loads are unknown. PLIL also include any long term load growth of the existing Top Consumers.

Since 1980/81, seven new major Industrial loads have been energized in Manitoba. Patterns of past unexpected load growth have been used to forecast future potential loads. The forecast is that PLIL will be zero through 2012/13. It will be 100 GW.h in 2013/14 and will increase 100 GW.h each year throughout the forecast. This will bring it to 1,800 GW.h by 2030/31.

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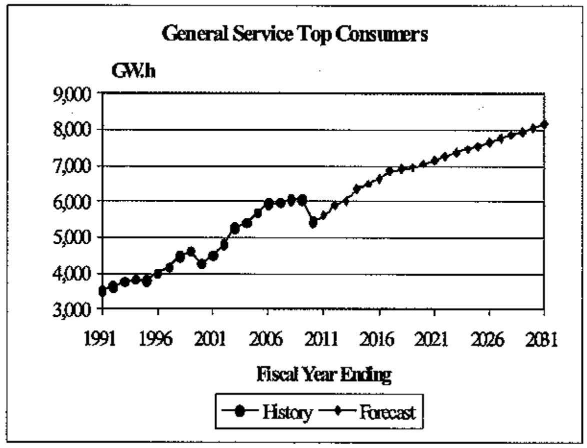
Figure 7



The adjacent graph shows that the Top Consumers category has grown consistently over the last twenty years. This group is very sensitive to economic conditions, especially apparent by their drop in consumption during the economic downturns of 1999/00 and 2009/10. In general, the Top Consumer recovery is expected in over the next two years and then return to near normal growth.

The Top Consumer category is forecast to increase from a base of 5,461 GW.h in 2009/10 to 8,163 GW.h by 2030/31. This represents an average growth of 129 GW.h or 1.9% per year. This is a higher growth rate than any other sector in Manitoba. But this is still less than the growth rate from 3,545 GW.h in 1990/91 to 5,461 GW.h in 2009/10 during which time the growth averaged 2.2% per year.

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Table 8

BASIC GENERAL SERVICE SALES
Base Forecast
1999/00 - 2030/31

Fiscal	Mass Market			Top Consumers			Total Basic		
Year	(Custs.)	(GW.h)	(Avg.)	(Custs.)	(GW.h)	(Avg.)	(Custs.)	(GW.h)	(Avg.)
1999/00	59494	6796	114232	35	4299	122833677	59529	11095	186385
2000/01	59759	7110	118970	31	4515	145639850	59790	11624	194420
2001/02	60086	7084	117902	25	4818	192739001	60111	11903	198013
2002/03	60265	7467	123900	26	5282	203139444	60291	12748	211449
2003/04	60672	7460	122955	27	5423	200857671	60699	12883	212245
2004/05	60924	7516	123362	26	5714	219774330	60950	13230	217060
2005/06	61491	7587	123380	26	5948	228753323	61517	13534	220009
2006/07	63596	7839	123269	26	5989	230346465	63622	13828	217353
2007/08	63855	8006	125382	26	6075	233643398	63881	14081	220425
2008/09	64140	8049	125485	26	6065	233277664	64166	14114	219958
2009/10	64758	7985	123304	26	5461	210031369	64784	13446	207547
2010/11	65246	8165	125142	25	5610	224400000	65271	13775	211043
2011/12	65639	8305	126520	25	5909	236360000	65664	14214	216461
2012/13	66039	8439	127788	25	6033	241320000	66064	14472	219060
2013/14	66425	8569	129005	25	6375	255000000	66450	14944	224893
2014/15	66764	8681	130020	26	6499	249961538	66790	15180	227275
2015/16	67090	8786	130962	26	6666	256384615	67116	15452	230232
2016/17	67432	8899	131964	26	6857	263730769	67458	15756	233562
2017/18	67770	9010	132952	26	6917	266038462	67796	15927	234928
2018/19	68112	9123	133938	26	6963	267807692	68138	16086	236076
2019/20	68453	9236	134924	26	7063	271653846	68479	16299	238014
2020/21	68798	9351	135920	26	7163	275500000	68824	16514	239946
2021/22	69144	9467	136921	26	7263	279346154	69170	16730	241872
2022/23	69492	9585	137926	26	7363	283192308	69518	16948	243789
2023/24	69842	9704	138938	26	7463	287038462	69868	17167	245702
2024/25	70192	9824	139966	26	7563	290884615	70218	17387	247621
2025/26	70546	9951	141050	26	7663	294730769	70572	17614	249582
2026/27	70901	10078	142137	26	7763	298576923	70927	17841	251536
2027/28	71257	10207	143244	26	7863	302423077	71283	18070	253499
2028/29	71616	10338	144351	26	7963	306269231	71642	18301	255449
2029/30	71976	10470	145466	26	8063	310115385	72002	18533	257396
2030/31	72338	10604	146583	26	8163	313961538	72364	18767	259335

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MANITOBA HYDRO 2009/2010 POWER RESOURCE PLAN

Date: September 16, 2009

The purpose of this power resource plan is:

- To provide a recommended long-term development plan, and
- To provide an alternative long-term development plan, in recognition of the uncertainties associated with the recommended plan.

2009/10 Recommended Power Resource Development Plan

The recommended development plan for major infrastructure and resources to pursue a new interconnection and facilitate the Wisconsin Public Service (WPS) and Minnesota Power (MP) sales is as follows:

- The 500 MW Sale to WPS and the 250 MW Sale to MP as described in the Term Sheets in effect.
- Keeyask for a 2018/19 ISD (In-Service Date)
- Conawapa for a 2022/23 ISD.
- A 1000 MW export and 750 MW import interconnection with a 2018/19 ISD.
- Additional north-south transmission beyond a 2000 MW Bipole III, as required for both Conawapa and Keeyask with a 2023/24 ISD.
- The 375/500 MW Sale to Northern States Power (NSP) as described in the Term Sheet in effect.
- 300 MW of additional wind generation with a 2010/11 ISD.
- Wuskwatim with a 2011/12 ISD.
- Pointe du Bois rebuilt with a 2016/17 ISD.

Table 1a at the end of this document details the annual dependable energy supply and demand values of this plan. Table 1b details the annual winter peak capacity supply and demand values of this plan.

2009/10 Alternative Power Resource Development Plan

The alternative development plan for major infrastructure and resources to meet Manitoba requirements without a new interconnection and without the WPS or MP sales is as follows:

- Conawapa with a 2021/22 ISD.
- A Combined Cycle Gas Turbine (400 MW) with a 2033/34 ISD.
- The 375/500 MW Sale to NSP as described in the Term Sheet in effect.
- 300 MW of additional wind generation with a 2010/11 ISD.
- Wuskwatim with a 2011/12 ISD.
- Pointe du Bois rebuilt with a 2016/17 ISD.

Table 2a at the end of this document details the annual dependable energy supply and demand values of this plan. Table 2b details the annual winter peak capacity supply and demand values of this plan.

Assumptions Common to Both Development Plans

The following summarizes the characteristics of major infrastructure and additional supply initiatives common to both development plans:

New Hydro			
Wuskwatim	200 MW gross	200 MW net	
Keeyask	695 MW gross	630 MW net	
Conawapa	1485 MW gross	1300 MW net	
Supply-Side Enhancement Projects (SSE)			
Planned Additional:			
Kelsey Rerunnering	77 MW /	0 GW.h for 2012/13	
Winnipeg River Plants Rerunnering	30 MW /	30 GW.h	
HVDC Bipole III Line (West)	89 MW /	243 GW.h by 2017/18	
License Review and Continued Operation:			
Selkirk #1-2	132 MW /	953 GW.h	
Brandon #5 Licence Review	105 MW /	811 GW.h	to 2018/19
Pointe du Bois (rebuilt)	120 MW /	620 GW.h	2016/17 (total plant)
Demand Side Management Program (DSM)			
Planned additional (by Mar 2025)	269 MW / 1158 GW.h		

Table 1a - Recommended Development Plan

System Firm Energy Demand and Dependable Resources (GW.h)

2009 Base Load Forecast

Fiscal Year	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Power Resources																		
Manitoba Hydro Plants																		
Existing	21110	21090	21080	21060	21040	21030	20920	20900	20880	20870	20850	20840	20830	20820	20820	20810	20560	20560
Wuskwatim			550	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250
Conawapa (net addition)														2151	4550	4550	4550	4550
Keeyask (net addition)										1371	2900	2900	2900	2900	2900	2900	2900	2900
Bipole III HVDC LINE									243	243	258	258	258	258	162	162	162	162
Manitoba Thermal Plants																		
Brandon Unit 5 (Drought Operation)	811	811	811	811	811	811	811	811	811	811								
Selkirk	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
Brandon Units 6-7 SCCT	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354
New Thermal																		
CCGT																		
SCGT																		
Wind Power: 400 MW	320	818	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254
Demand Side Management	244	440	606	719	819	842	798	825	890	949	993	1037	1082	1115	1151	1158	1133	1100
Major Rerunnering (incremental to existing)																		
Kelsey Rerunnering																		
Pointe du Bois Redeveloped								60	150	150	150	150	150	150	150	150	150	150
Imports																		
Total	2796	2796	2796	2796	2705	2705	2410	2414	2414	2797	3258	3846	3948	4652	4715	4715	4014	3876
TOTAL POWER RESOURCES	28588	29262	30404	31197	31186	31199	30750	30821	31198	33001	34220	34842	34979	37857	40259	40256	39280	39109
Demand																		
2009 Base Load Forecast	24239	24759	25323	25763	26177	26783	27137	27495	27808	28088	28452	28818	29185	29555	29927	30300	30681	31063
Non-Committed Construction Power			10	30	55	90	100	120	125	100	80	80	100	90	30	5	0	0
Exports																		
Total	3626	3404	3385	3259	3156	3156	1560	1352	1352	1926	2614	3494	3648	4992	5086	5086	3589	3589
Total Demand	27865	28163	28718	29052	29388	30029	28797	28967	29285	30114	31146	32392	32933	34637	35043	35391	34270	34652
SURPLUS (w/ B#5)	723	1099	1686	2145	1798	1171	1953	1854	1913	2888	3074	2450	2046	3220	5216	4865	5011	4457
EXPORTABLE SURPLUS		288	875	1334	987	360	1142	1043	1102	2077	3074	2450	2046	3220	5216	4865	5011	4457

numbers are rounded to the nearest whole number

Table 1a - Recommended Development Plan

System Firm Energy Demand and Dependable Resources (GW.h)

2009 Base Load Forecast

Fiscal Year	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45
Power Resources																		
Manitoba Hydro Plants																		
Existing	20550	20540	20540	20530	20530	20520	20510	20510	20500	20490	20490	20480	20480	20470	20460	20460	20450	20440
Wuskwatim	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250
Conawapa (net addition)	4550	4550	4550	4550	4550	4550	4550	4550	4550	4550	4550	4550	4550	4550	4550	4550	4550	4550
Keeyask (net addition)	2900	2900	2900	2900	2900	2900	2900	2900	2900	2900	2900	2900	2900	2900	2900	2900	2900	2900
Bipole III HVDC LINE	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162
Manitoba Thermal Plants																		
Brandon Unit 5 (Drought Operation)																		
Selkirk	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
Brandon Units 6-7 SCCT	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354
New Thermal																		
CCGT																		
SCGT																443	886	1329
Wind Power: 400 MW	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254	1254
Demand Side Management	1066	1070	1046	1027	1009	990	970	949	925	901	877	855	855	855	855	855	855	855
Major Rerunnering (incremental to existing)																		
Kelsey Rerunnering																		
Pointe du Bois Redeveloped	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Imports																		
Total	3876	3876	3876	3237	3109	2470	2342	2342	2342	2342	2342	2342	2342	2342	2342	2342	2342	2342
TOTAL POWER RESOURCES	39065	39059	39035	38368	38221	37553	37395	37374	37340	37306	37282	37250	37250	37240	37230	37673	38106	38539
Demand																		
2009 Base Load Forecast	31450	31838	32230	32622	33014	33405	33797	34189	34581	34973	35364	35756	36148	36540	36932	37323	37715	38107
Non-Committed Construction Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Exports																		
Total	3589	3589	3589	2633	2441	1485	1293	1293	239	145	145	145	145	145	145	145	145	145
Total Demand	35039	35427	35819	35255	35455	34890	35090	35482	34820	35118	35509	35901	36293	36685	37077	37468	37860	38252
SURPLUS (w/ B#5)	4027	3632	3216	3113	2766	2662	2305	1892	2521	2189	1772	1349	957	555	153	204	246	287
EXPORTABLE SURPLUS	4027	3632	3216	3113	2766	2662	2305	1892	2521	2189	1772	1349	957	555	153	204	246	287

numbers are rounded to the nearest whole number

Table 1b - Recommended Development Plan

System Firm Capacity (Winter Peak) Demand and Resources (MW)

2009 Base Load Forecast

Fiscal Year	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Power Resources																		
Manitoba Hydro Plants																		
Existing	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900
Wuskwatim			200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Conawapa (net addition)														520	1040	1300	1300	1300
Keeyask (net addition)										90	450	630	630	630	630	630	630	630
Bipole III HVDC LINE									89	89	79	79	79	79	10	10	10	10
Manitoba Thermal Plants																		
Brandon Unit 5 (Drought Operation)	105	105	105	105	105	105	105	105	105	105								
Selkirk	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
Brandon Units 6-7 SCCT	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298
New Thermal																		
CCGT																		
SCGT																		
Wind Power: 400 MW																		
(Wind has no dependable capacity for Winter Peak)																		
Demand Side Management	39	88	129	159	181	185	188	193	206	218	228	238	247	256	265	269	261	249
Major Rerunnering (incremental to existing)																		
Kelsey Rerunnering		11	34	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77
Pointe du Bois Redeveloped								43	43	43	43	43	43	43	43	43	43	43
Imports																		
Total	616	616	616	616	550	550	385	385	385	385	385	385	385	385	385	385		
TOTAL POWER RESOURCES	6090	6150	6414	6487	6443	6447	6285	6333	6435	6537	6792	6982	6992	7520	7980	8244	7851	7839
Demand																		
2009 Base Load Forecast	4363	4437	4530	4601	4664	4765	4820	4876	4924	4973	5038	5103	5168	5233	5299	5365	5432	5500
Non-Committed Construction Power																		
Exports																		
Total	693	638	638	605	605	605	413	413	413	578	743	963	963	1375	1375	1375	825	825
Total Demand	5056	5075	5168	5206	5269	5370	5232	5288	5336	5551	5780	6065	6130	6608	6674	6740	6257	6325
Reserve	445	448	454	459	472	483	510	516	520	524	531	538	544	551	558	565	621	630
TOTAL PEAK DEMAND	5501	5522	5622	5665	5741	5853	5742	5804	5856	6075	6311	6603	6674	7159	7232	7305	6878	6955
SURPLUS (w/ B#5)	589	627	792	823	702	594	543	528	579	462	481	379	318	361	748	938	973	884
EXPORTABLE SURPLUS	484	522	687	718	597	489	438	423	474	357	481	379	318	361	748	938	973	884

numbers are rounded to the nearest whole number

Table 1b - Recommended Development Plan

System Firm Capacity (Winter Peak) Demand and Resources (MW)

2009 Base Load Forecast

Fiscal Year	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45
Power Resources																		
Manitoba Hydro Plants																		
Existing	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900	4900
Wuskwatim	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Conawapa (net addition)	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300
Keeyask (net addition)	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630
Bipole III HVDC LINE	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Manitoba Thermal Plants																		
Brandon Unit 5 (Drought Operation)																		
Selkirk	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
Brandon Units 6-7 SCCT	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298	298
New Thermal																		
CCGT																		
SCGT																53	106	159
Wind Power: 400 MW																		
(Wind has no dependable capacity for Winter Peak)																		
Demand Side Management	235	236	230	226	224	221	217	212	208	203	198	194	194	194	194	194	194	194
Major Rerunnering (incremental to existing)																		
Kelsey Rerunnering	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77
Pointe du Bois Redeveloped	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
Imports																		
Total																		
TOTAL POWER RESOURCES	7825	7826	7820	7816	7814	7811	7807	7802	7798	7793	7788	7784	7784	7784	7784	7837	7890	7943
Demand																		
2009 Base Load Forecast	5568	5637	5706	5776	5845	5914	5984	6053	6123	6192	6261	6331	6400	6469	6539	6608	6677	6747
Non-Committed Construction Power																		
Exports																		
Total	825	825	825	550	550	275	275	275										
Total Demand	6393	6462	6531	6326	6395	6189	6259	6328	6123	6192	6261	6331	6400	6469	6539	6608	6677	6747
Reserve	640	648	657	666	675	683	692	701	710	719	728	736	745	753	761	770	778	786
TOTAL PEAK DEMAND	7033	7110	7189	6992	7070	6873	6951	7029	6832	6911	6989	7067	7145	7222	7300	7378	7455	7533
SURPLUS (w/ B#5)	791	715	631	825	744	938	856	773	965	882	799	717	639	562	484	459	435	410
EXPORTABLE SURPLUS	791	715	631	825	744	938	856	773	965	882	799	717	639	562	484	459	435	410

numbers are rounded to the nearest whole number

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Table 3
Existing System Capacity and Energy Availability
Reflected in Supply - Demand Tables

Source of Energy	Winter Peak Capacity (MW)	Dependable Energy (GW.h)	Average Energy (GW.h)
Hydro Total	4900	21110	29250
Thermal Total	535	4118	205
Wind Total	0	320	375
System Total	5435	25548	29830

Table 4
Potential New Resources

Project	Winter Peak Capacity (MW)	Dependable Energy (GW.h)	Average Energy (GW.h)	Earliest ISD
New additions in Recommended Plan:				
Wuskwatim	200	1250	1520	2011/12
Keeyask	695	2900	4430	2018/19
Conawapa	1485	4550	7000	2021/22
Pointe du Bois rebuilt	120	620	805	2016/17
Kelsey Rerunnering	77	0	350	2012/13
Churchill River Diversion Stations:				
Notigi	100	625	750	>2030
First Rapids	225	1400	1600	>2030
Manasan	200	1250	1400	>2030
Lower Nelson River Stations:				
Birthday	460	1900	2600	>2030
Gillam Island	820	3500	5040	>2030
Upper Nelson River Stations:				
White Mud	300	1450	2000	>2030
Red Rock	250	1700	2250	>2030
Upper Churchill River Stations:				
Bonald	120	400	650	>2030
Granville Falls	125	410	670	>2030

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Reference: Glossary of Terms/Order 150/08 Directive #2 Exports and Imports Transactions

a) Please provide a definition of the following export/import transactions as employed by MH:

Firm Contract Sales

- **Dependable**
- **Merchant**

Opportunity Sales Bilateral

- **Two weeks forward written contracts.**
- **Day ahead [verbal].**
- **Real Time [verbal].**

Market

- **Day Ahead.**
- **Real Time.**

Other Sales

ANSWER:

The following is a description of the various export/import transactions identified above:

Firm Contract Sales – Dependable

Export sales that are sourced from Manitoba Hydro's dependable energy resources and include the associated product of accreditable capacity and have duration of greater than six months.

Merchant Sales

Manitoba Hydro's merchant transactions are the sale of electricity not involving Manitoba Hydro's generation assets or not related to serving or hedging its sales obligations.

Opportunity Sales Bilateral – Two weeks forward written contracts
Export sales transactions with a customer that has a term equal to or exceeding two weeks in duration and are executed and documented with a written contract.

Opportunity Sales Bilateral – Day Ahead [Verbal]
Export sales transactions that are executed on a day-ahead basis (next operating day) and are documented verbally with the purchasing party over a recorded telephone line.

Opportunity Sales Bilateral – Real Time [Verbal]
Export sales transactions that are executed in the real time market (same day) and are documented verbally with the purchasing party over a recorded telephone line.

Market – Day Ahead
Export sales transactions in a market operated by an independent system operator for the purchase and sale of power related products for the next operating day.

Market – Real Time
Export sales transactions in a market operated by an independent system operator for the purchase and sale of power related products during the operating day.

Other Sales
Revenues received from export markets (such as wheeling services, transmission credits, environmental attributes) generally from the sale of services not associated with energy or capacity.

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PUB/MH/RISK-80

Reference: **KPMG Report – Drought Scenarios Appendix J, MH's Price History-2007 Hearing PUB/MH I-23, I-29**

Risk Issue: **2006/07 Energy Supply**

b) Please confirm that in 2006/07 Q1, MH achieved an average price of 3.7¢/KWh, 3,000 GWh opportunity sales (and 4.2¢/KWh for all sales) and in 2006/07 Q2, achieved an average price of 5.2¢/KWh for 2,500 GWh opportunity sales (5.4¢/KWh for all sales), but was faced with the purchase of 1,500 GWh of energy at 5.5¢/KWh in 2006-07 Q3 resulting in what could be viewed as an energy marketing loss.

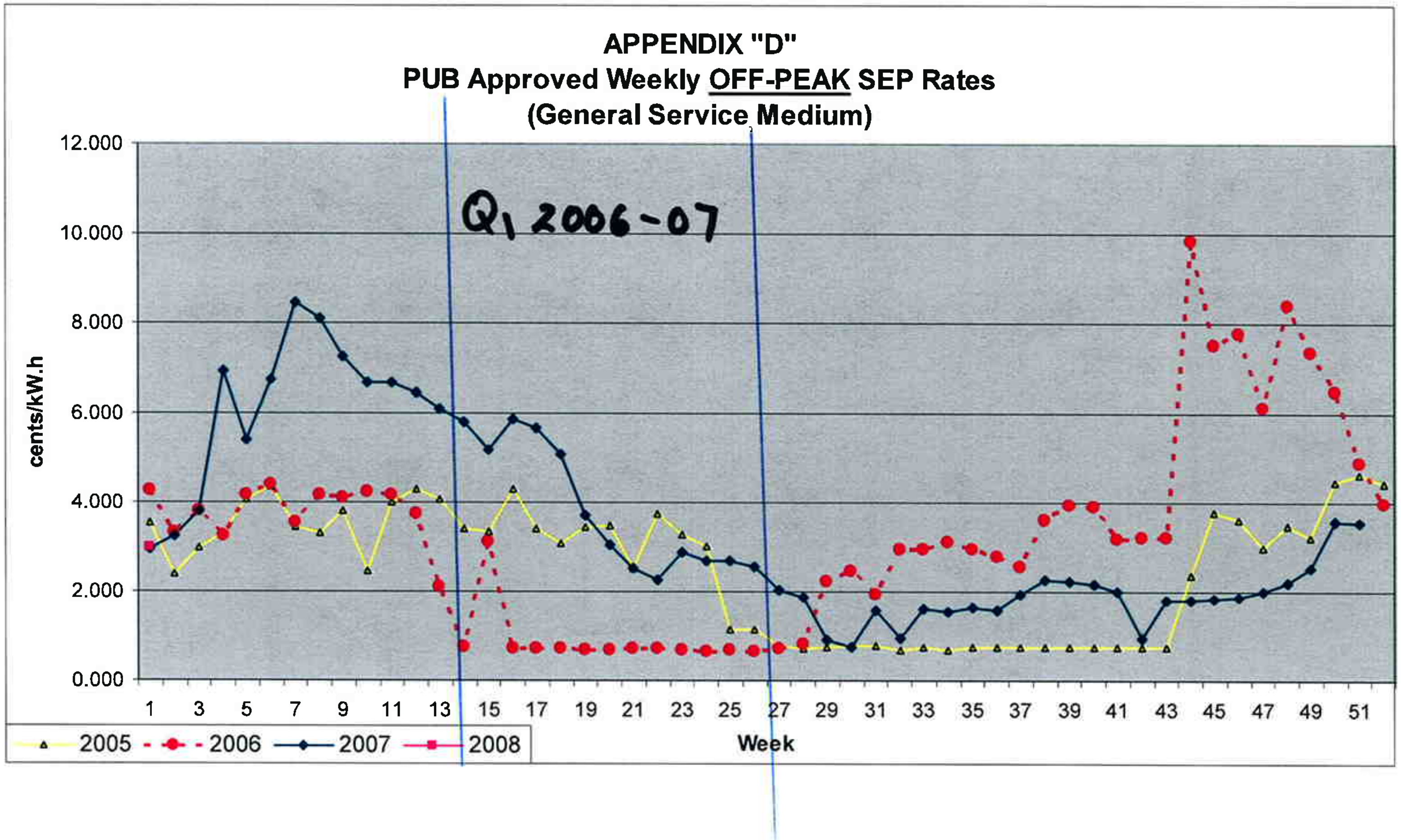
ANSWER:

The numbers provided above for 2006/07 Q1 and Q2 sales are approximately correct, however the numbers provided for 2006/07 Q3 purchases include System Merchant whereas the sales numbers provided do not include System Merchant. Please see table below which reflects the sales as reported above as well as the purchases excluding the System Merchant.

Manitoba Hydro does not agree these results indicate an energy marketing loss.

	Q1			Q2			Q3			Q4		
	GWh	$	¢/KWh	GWh	$	¢/KWh	GWh	$	¢/KWh	GWh	$	¢/KWh
Opportunity Sales	3,039	115,964,988	3.8	2,317	118,507,997	5.1	486	30,306,466	6.2	407	30,434,180	7.5
Dependable Sales	695	52,273,287	7.5	1,078	60,748,703	5.6	842	52,030,229	6.2	838	52,961,583	6.3
Total Sales	3,734	168,238,275	4.5	3,396	179,256,700	5.3	1,329	82,336,695	6.2	1,246	83,395,763	6.7
Total Purchases	191	5,206,042	2.7	280	14,386,983	5.1	1,116	54,490,114	4.9	662	38,606,759	5.8

ORDER 165/07



APPENDIX "D"
PUB Approved Weekly OFF-PEAK SEP Rates
(General Service Medium)
Q1 2006-07
12.000
10.000
8.000
6.000
4.000
2.000
0.000
cents/kW.h
1 3 5 7 9 11 13 15 17 19 21 23 25 27 29 31 33 35 37 39 41 43 45 47 49 51
Week
2005
2006
2007
2008

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CAC/MSOS/MH I-13

Subject: **Financial Results and Forecast – Extraprovincial Revenue**
Reference: **Tab 4, pages 6-8**

d) **Please provide an update to CAC/MSOS (MH) 1 –33 a) {per 2008 GRA}.**

ANSWER:

Tables below have been updates as per the 2008 GRA with values to December 2009 for the 2009/10 fiscal year.

TOTAL SALES						
	DEPENDABLE SALES		OPPORTUNITY SALES		SYSTEM MERCHANT SALES	
	GWh	CAD $	GWh	CAD $	GWh	CAD $
2000/01	6,352	223,138,576	5,801	216,927,371	0	0
2001/02	6,277	322,068,849	6,022	280,792,868	0	0
2002/03	6,544	339,221,224	3,191	137,117,410	0	0
2003/04	6,231	295,476,336	735	52,185,471	11	473,904
2004/05	5,633	289,749,063	4,798	239,277,193	315	10,518,118
2005/06	4,044	239,590,165	10,303	510,384,667	919	62,926,861
2006/07	3,654	218,013,802	6,250	295,213,631	1,206	60,134,039
2007/08	3,921	208,629,442	7,814	327,826,886	1,262	71,548,902
2008/09	4,087	233,466,153	6,489	286,653,254	1,598	85,958,504
2009/10	2,613	147,423,918	6,554	145,683,166	541	17,569,845

TOTAL U.S. SALES									
	U.S. DEPENDABLE SALES			U.S. OPPORTUNITY SALES			U.S. SYSTEM MERCHANT SALES		
	GWh	CAD $	US $	GWh	CAD $	US $	GWh	CAD $	US $
2000/01	4,895	199,168,895	169,908,422	4,511	166,675,224	142,165,381	0	0	0
2001/02	4,767	262,865,376	168,100,356	5,083	247,381,289	157,623,656	0	0	0
2002/03	4,947	277,448,984	179,618,184	2,713	114,747,101	74,942,044	0	0	0
2003/04	5,245	259,347,230	189,868,274	507	35,187,891	27,499,575	0	3,710	2,797
2004/05	5,633	289,749,063	226,341,463	3,218	170,503,849	136,723,761	109	1,163,641	901,572
2005/06	4,044	239,590,165	201,202,052	8,879	400,507,197	336,700,704	0		
2006/07	3,654	218,013,802	192,260,768	5,877	270,180,884	240,553,600	0	0	0
2007/08	3,921	208,629,442	202,672,290	7,332	288,915,585	279,839,294	0	0	0
2008/09	4,087	233,466,153	209,114,260	6,071	236,966,187	218,656,448	0	0	0
2009/10	2,613	147,423,918	134,276,396	6,218	122,882,922	112,517,145	33	1,525,389	1,326,001

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OPPORTUNITY EXPORTS				
	On Peak GWh	Off Peak GWh	On Peak Avg Price (CAD $)	Off Peak Avg Price (CAD $)
2005/06	4,485	5,819	70.62	34.26
2006/07	2,876	3,374	62.84	34.61
2007/08	3,785	4,029	65.70	29.52
2008/09	3,133	3,360	70.70	27.11
2009/10	2,833	3,498	28.31	14.51

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PUB/MH/RISK-115

Reference: **NYC/MH Risk Issue #26 (Page 26), Pages 166 to 171**
KPMG – Main Report, Exhibit 4-17, ICF 2009 Report (Page 92)
Risk Issue: **Diversity Sales/Purchase**

c) **Please provide a monthly tabular comparison (MW/GWh and ¢/KWh) of MH's ongoing exports, buybacks, and energy purchases for the August 2002 to June 2004 period.**

ANSWER:

	Physical Exports		Physical Imports		Buybacks	
	MWh	c/KWh	MWh	c/KWh	MWh	c/KWh
Aug-02	1,037,276	5.2	74,978	2.1	10,066	3.9
Sep-02	939,432	4.6	71,478	2.0	1,565	5.9
Oct-02	780,722	4.5	114,077	2.1	240	3.5
Nov-02	627,373	5.0	330,807	2.7	17,443	3.6
Dec-02	643,451	5.1	357,014	2.8	2,880	5.0
Jan-03	691,954	5.0	407,463	4.1	4,416	4.6
Feb-03	581,182	5.4	498,819	5.2	4,390	5.7
Mar-03	620,172	5.3	554,890	5.6	26,075	10.5
Apr-03	668,671	5.1	463,628	3.9	11,535	5.3
May-03	635,293	4.9	389,448	2.4	1,515	3.0
Jun-03	617,020	4.8	616,638	3.3	58,764	3.2
Jul-03	643,519	5.7	524,563	5.2	192,972	6.4
Aug-03	546,869	6.3	638,231	5.8	224,430	6.9
Sep-03	271,494	7.2	606,374	4.2	275,025	5.4
Oct-03	194,249	8.5	626,348	4.3	362,394	5.9
Nov-03	96,385	12.1	684,345	4.4	294,355	5.7
Dec-03	147,017	8.8	659,019	4.5	314,734	6.0
Jan-04	122,776	11.4	765,481	6.5	302,888	7.3
Feb-04	132,919	10.3	584,120	7.0	277,846	7.3
Mar-04	318,831	6.7	515,052	6.2	225,570	6.0
Apr-04	240,025	8.5	260,961	3.9	267,021	6.3
May-04	472,523	7.0	228,523	3.9	132,808	4.1
Jun-04	717,793	5.4	88,350	4.3	44,025	3.3

PUB/MH/RISK-94

Reference: **KPMG Page 40 Exhibit 3-2**
Risk Issue: **Export Sales Breakdown**

Please provide the same level of detail in Exhibit 3-2 for the years 2002/03 through 2009/10.

ANSWER:

The data requested is provided in the table below. Note that in the referenced Exhibit 3-2 the data that was presented as "Hydraulic Generation in 2008/09 as % of Hydraulic Generation in an Average Flow Year" of 114%, this actually represents a percentage of generation in a Median flow year, the percentage of generation in an Average Flow Year for 2008/09 is actually 117%.

Sales Category	2002/03 Volumes (MWh)	%	2003/04 Volumes (MWh)	%	2004/05 Volumes (MWh)	%	2005/06 Volumes (MWh)	%	2006/07 Volumes (MWh)	%	2007/08 Volumes (MWh)	%	2008/09 Volumes (MWh)	%	2009/10 Volumes (MWh)	%
Opportunity Spot (DA and RT)	1,315,092	13%	531,277	8%	3,327,716	32%	8,085,539	56%	2,977,409	29%	6,216,880	53%	4,145,046	44%	5,128,774	47%
Opportunity Term	2,391,479	24%	468,058	7%	1,613,454	15%	2,216,831	15%	3,277,537	32%	1,596,514	14%	1,185,392	13%	2,593,658	24%
Dependable	6,198,545	63%	5,917,562	86%	5,617,614	53%	4,138,806	29%	3,848,905	38%	4,010,803	34%	4,145,046	44%	3,264,433	30%
Total	9,905,116	100%	6,916,897	100%	10,558,784	100%	14,441,176	100%	10,103,851	100%	11,824,197	100%	9,475,484	100%	10,986,865	100%
Hydraulic Generation as a % of Hydraulic Generation in an Average Flow Year	98%		63%		106%		127%		108%		119%		117%		116%	

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IMPORT REQUIREMENTS/PRICING
(Exports in Excess of Hydraulic Generation)

Year	Summer Shortfall Buyback (%)	SEP Off-Peak Selling Prices (¢/KWh)	Winter Shortfall Buybacks (%)	SEP Off-Peak Buying Prices (¢/KWh)	Actual Total Purchases/ Buybacks[1] (GWh/¢/KWh)
2000/01	30%	2.0-3.0	70%	3.0-4.0	900 @ 3.2
2001/02	20%	1.5-2.5	80%	2.0-3.0	1,500 @ 3.8
2002/03	30%	2.0-3.0	70%	2.0-7.0	3,200 @ 3.9
2003/04	35%	4.0-9.5	65%	6.5-11.5	9,600 @ 5.3
2004/05	45%	4.0-4.5	55%	3.0-4.5	1,600 @ 4.4
2005/06	30%	2.0-3.5	70%	2.0-4.0	500 @ 4.7
2006/07	15%	1.0-3.5	85%	4.0-8.0	2,200 @ 5.2
2007/08	N/A	1.0-3.0	N/A	3.0-4.0	300 @ 3.7
2008/09	N/A	1.5-2.0	N/A	2.5-3.5	1,000 @ 5.3
2009/10	N/A	0.7-1.5	N/A	1.5-2.5	1,300 @ 2.5 to 4.0

Note:

(1) Merchant sales are excluded from above purchases.

Sources:

- NEB Data.
- PUB/MH II-191(a) (B.O.D. 6
- SEP Reporting.
- MH Filings at Prior Hearings (actual exports and imports – 2007/12/05).
- Annual Reports.
- PUB/MH I-152.

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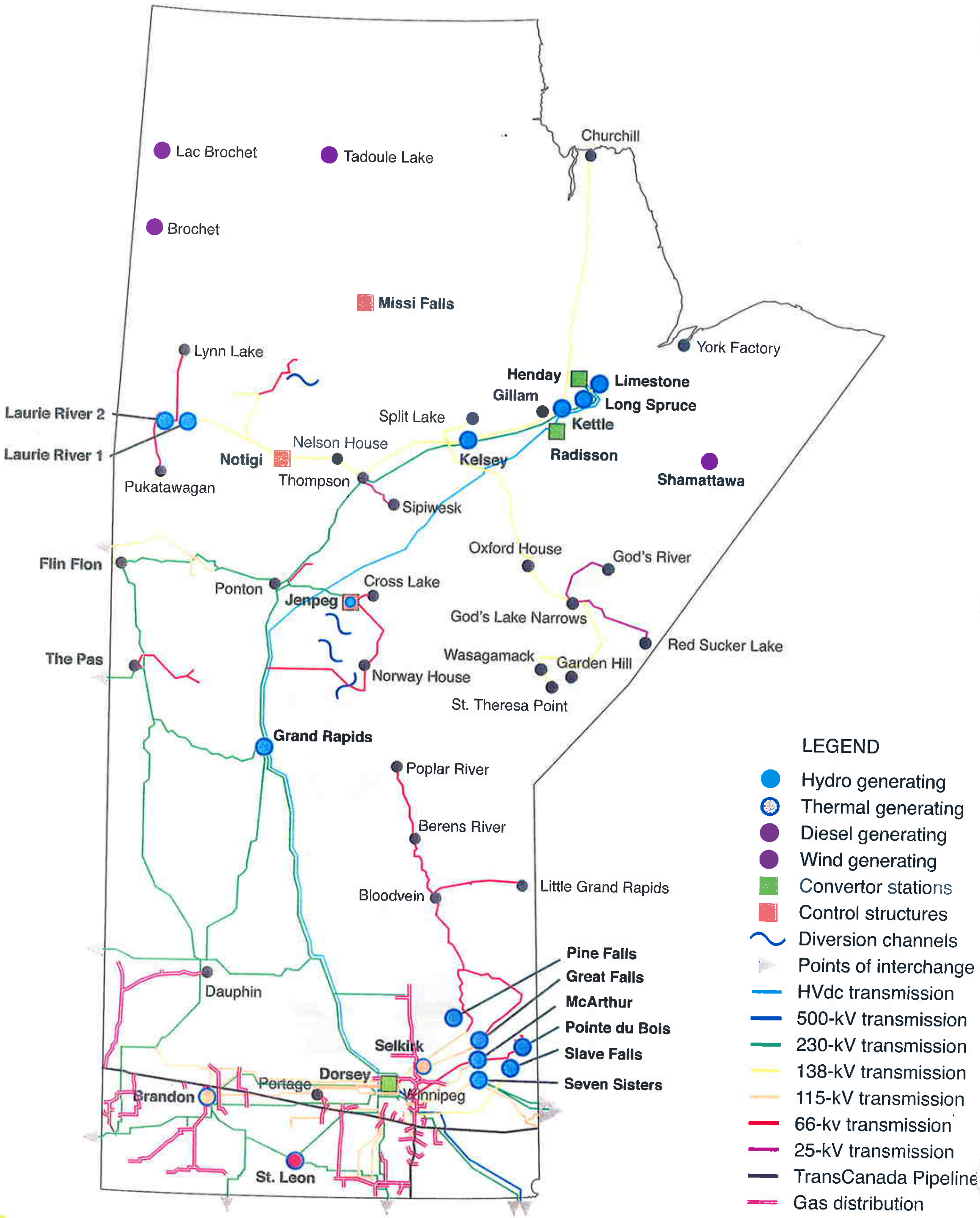
Churchill
Lac Brochet
Tadoule Lake
Brochet
Missi Falls
Lynn Lake
York Factory
Henday
Limestone
Gillam
Long Spruce
Split Lake
Kettle
Laurie River 2
Laurie River 1
Nelson House
Notigi
Kelsey
Radisson
Shamattawa
Thompson
Pukatawagan
Sipiwesk
Oxford House
God's River
Flin Flon
Ponton
Cross Lake
Jenpeg
God's Lake Narrows
Red Sucker Lake
The Pas
Wasagamack
Garden Hill
Norway House
St. Theresa Point
Grand Rapids
Poplar River
Berens River
Bloodvein
Little Grand Rapids
Pine Falls
Great Falls
McArthur
Pointe du Bois
Slave Falls
Seven Sisters
Dauphin
Selkirk
Dorsey
Portage
Brandon
Winnipeg
St. Leon
LEGEND
Hydro generating
Thermal generating
Diesel generating
Wind generating
Convertor stations
Control structures
Diversion channels
Points of interchange
HVdc transmission
500-kV transmission
230-kV transmission
138-kV transmission
115-kV transmission
66-kv transmission
25-kV transmission
TransCanada Pipeline
Gas distribution

SOURCES OF ELECTRICAL ENERGY

Sources of Electrical Energy Generated and Imported

For the Year Ended March 31, 2010

Nelson River	81.44	%
Billion kWh generated	28.2	
Limestone	27.06	%
Kettle	25.66	%
Long Spruce	21.20	%
Kelsey	4.93	%
Jenpeg	2.59	%
Winnipeg River	12.62	%
Billion kWh generated	4.4	
Seven Sisters	3.60	%
Great Falls	2.93	%
Pine Falls	2.04	%
Pointe du Bois	1.75	%
Slave Falls	1.00	%
McArthur	1.30	%

Saskatchewan River	3.37	%
Billion kWh generated	1.2	
Grand Rapids	3.37	%
Laurie River	0.18	%
Billion KW.h generated	0.1	
Laurie River #1	0.10	%
Laurie River #2	0.08	%

Thermal	0.41	%
Billion kWh generated	0.1	
Brandon	0.32	%
Selkirk	0.09	%
Imports	1.02	%
Billion kWh imported	0.4	
Wind	0.96	%
Billion kWh imported	0.3	

Generating Stations and Capabilities

For the Year Ended March 31, 2010

Interconnected Capabilities

Station	Location	Number of units	Net Capability (MW)
Hydraulic			
Great Falls	Winnipeg River	6	136
Seven Sisters	Winnipeg River	6	165
Pine Falls	Winnipeg River	6	89
McArthur	Winnipeg River	8	55
Pointe du Bois	Winnipeg River	16	77
Slave Falls	Winnipeg River	8	67
Grand Rapids	Saskatchewan River	4	479
Kelsey	Nelson River	7	250
Kettle	Nelson River	12	1 220
Jenpeg	Nelson River	6	135
Long Spruce	Nelson River	10	1 010
Limestone	Nelson River	10	1 340
Laurie River (2)	Laurie River	3	10
Thermal			
Brandon		3	339
Selkirk		2	129
Isolated Capabilities			
Diesel			
Brochet			3
Lac Brochet			2
Shamattawa			3
Tadoule Lake			2
Total Generating Capability			5 511

Energy Supply Power Resource Plan

6.0 MH Hydraulic Generation Resources

- These are tabulated in the following tables:

Existing Hydraulic Generation (GWh)

Generation Station		Annual Energy Output under Dependable Hydraulic Condition	Mean Annual Energy Output over all Historic Flow Cases	Median Annual Energy Output over all Historic Flow Cases	Annual Energy Output under High Flow Conditions
	(MW)	(GWh/yr)	(GWh/yr)	(GWh/yr)	(GWh/yr)
Pointe du Bois	(78)	280	610	610	410
Slave Falls	(67)	260	520	550	580
Seven Sisters	(165)	630	1020	1070	1220
McArthur	(55)	230	390	410	470
Great Falls	(131)	550	920	970	1010
Pine Falls	(88)	350	640	680	720
Grand Rapids	(479)	1370	1530	1450	2520
Jenpeg	(132)	680	960	1020	940
Kelsey	(223)	1580	2100	2190	2050
Kettle	(1220)	4750	6990	7010	8960
Long Spruce	(1010)	3890	5960	5970	7830
Limestone	(1340)	5140	7480	7500	9900
Laurie River I	(5)	20	30	30	40
Laurie River II	(5)	20	30	30	40
Total Hydro-Electric		**19750**	**29180**	**29490**	**36690**

Table from: GRA PUB/MH I-85a) & GS MW from Brochures

Notes: The dependable hydraulic condition refers to energy generated in fiscal year 1940/41. The mean and median energy output is based on historic record (1912/13 to 2005/06). The annual energy generated under high flow conditions refers to the energy generated in fiscal year 2005/06.

New Energy Supply

Source		Annual Energy Output under Dependable Hydraulic Condition	Mean Annual Energy Output over all Historic Flow Cases	Median Annual Energy Output over all Historic Flow Cases	Annual Energy Output under High Flow Conditions
		(GWh/yr)	(GWh/yr)	(GWh/yr)	(GWh/yr)
Bi- Pole III	(87 MW)	442			
Wuskwatim	(200 MW)	1220	1520	1600	1420
Keeyask	(600 MW)	2880	4380	4480	4740
Conawapa	(1300 MW)	4600	7060	7050	9760

Table from: PUB/MH I-85d) & GS MW from Resource Plan

Notes: Same as for above table.

After 2012-13 MH will have dependable flow hydraulic generation of 21,938 GWh and average energy output of 30,845 GWh. With the likely addition of Keeyask G.S. and Bi-Pole III to the Power Resource Plan, the dependable flow hydraulic generation will increase to 25,212 GWh and average energy output will be 33,644 GWh. After 2021-22 the in-service of Conawapa G.S. will raise the dependable flow hydraulic generation to 30,148 GWh and average energy output will increase to 36,133 GWh. The foregoing values include the other supply side enhancement such as Kelsey Rerunnering, Point du Bois, etc.

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MH Thermal Generation Resources

These are tabulated in the following table:

Existing Thermal Generation (GWh)

Generation Station	Annual Energy Output under Dependable Hydraulic Condition	Mean Annual Energy Output over all Historic Flow Cases	Median Annual Energy Output over all Historic Flow Cases	Annual Energy Output under High Flow Conditions
(MW)	(GWh/yr)	(GWh/yr)	(GWh/yr)	(GWh/yr)
Brandon Coal (5)	761	601	761	269
Selkirk (1&2)	963	136	32	32
Brandon CT (6&7)	2203	194	43	43
Total Thermal	**3928**	**931**	**835**	**343**

Table from: GRA PUB/MH I-85a)

- No changes to the supply assumptions for existing thermal generation resources (Brandon gas turbines #6 & 7, Brandon #5 and Selkirk #1 & 2 steam plants) have been made for the 2007/08 Power Resource Plan.
- For Brandon GS, the license review process is in progress and a revised environment act license is tentatively anticipated in 2008.
- Brandon and Selkirk operation will continue until at least 2018/19 and 2020/21 respectively.

MH's Wind Generation Resources

- The Current Wind Power under Contract with NUG at St. Leon is 100 MW and the Capacity Factor is 39%.
- A Request for Proposal (RFP) was issued by MH for up to a maximum of 300 MW of additional wind energy.
- The planned total of 400 MW of Wind Power is for 2013/14, although evaluation of implementation is being made.

MH's DSM Resources

- The 2007/08 Power Resource Plan includes incremental DSM savings from the preliminary 2007 **Power Smart** Plan to achieve the Corporate target of electricity savings of 839 MW / 2852 GWh by 2017/18. The Corporate target includes the savings to date of 434 MW / 1030 GWh already achieved by March 31, 2006.

Bi-Pole III

- MH is developing plans to proceed with introductory consultations with regulatory authorities, aboriginal communities, and rural towns and municipalities with regard to the developing of Bi-Pole III running from the Nelson River via the area west of Lake Winnipegosis and on the Riel Station site on the east side of Winnipeg. The earliest in-service date continues to be October 2017.

MH's Imports

- MH definition of Import is needed.
- MH has a high degree of confidence that energy deficits up to 3000 GWh/yr could be managed through imports. However this approach would increase the financial impact of drought.

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PUB/MH I-42(B)

Wuskwatim Power Limited Partnership (IFF09)
Projected Income Statement
For the fiscal years ending March 31
thousands of dollars

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Revenues	-	-	44,373	104,480	112,490	118,734	129,276	134,637	138,558	143,771	142,361
Expenses											
Operating & administrative	-	-	6,119	6,229	6,341	6,593	6,712	6,834	6,958	7,084	7,213
Depreciation	-	-	14,244	26,572	26,572	26,572	26,573	26,575	26,575	26,575	26,575
Water rentals	-	-	2,185	5,062	5,062	5,062	5,062	5,062	5,062	5,062	5,062
	-	-	22,548	37,864	37,975	38,228	38,348	38,471	38,595	38,721	38,850
Income/(loss) before finance expense	-	-	21,826	66,616	74,515	80,506	90,928	96,166	99,963	105,050	103,511
Finance expense	(0)	(0)	26,053	69,127	67,854	66,496	65,033	63,666	62,377	61,044	59,863
Net Income/(Loss)	**0**	**0**	**(4,228)**	**(2,510)**	**6,660**	**14,011**	**25,894**	**32,500**	**37,587**	**44,006**	**43,648**

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PUB/MH/RISK-2

Reference: **Appendix 12.1 Corporate Risk Management Report**
Risk Issue: **Market-Export Regulatory Environment A2.1**

a) Please provide the wording for all regulatory approvals and conditions for WPS and MP in the term sheets and an outline on the process to obtain the approvals.

ANSWER:

The terms and conditions of the WPS and MP Term Sheets are subject to a non-disclosure agreement between Manitoba Hydro and the respective parties.

In general, all Manitoba Hydro long-term export contracts require appropriate state/provincial and federal regulatory, final non-appealable approval. It is Manitoba Hydro's responsibility to obtain Canadian approvals whereas it is the purchaser's responsibility for U.S. approvals.

PUB/MH/RISK-2

Reference: Appendix 12.1 Corporate Risk Management Report
Risk Issue: Market-Export Regulatory Environment A2.1

b) Please indicate the prospects for Hydro—based generation to be considered renewable energy and discuss the implications on MH's Export prospects?

ANSWER:

Hydro based generation is a renewable energy source as it is derived from naturally replenished resources. However, each Renewable Portfolio Standard defines specific technologies that are eligible or qualify under its system. These definitions tend to vary from a true definition of renewability and are often driven by differing and sometimes unstated objectives such as encouraging: non-emitting technologies; emerging technologies; and local economic development.

Although most Renewable Portfolio Standard definitions recognize hydro generation, they often contain limitations related to the size of the facility. MH's small generating stations (less than 100 MW) are eligible under Minnesota's current Renewable Portfolio Standard. While Minnesota's standard is unlikely to change in the near term, there is potential for other state systems to become more inclusive. For instance, in 2010 a bill was promoted in Wisconsin that would have included new hydro regardless of size. While this Wisconsin bill was not voted on in 2010, Wisconsin based utilities are expected to continue to push for these amendments. Vermont recent announced its intention to fully include hydro power from Quebec in its definition of eligible renewable resources.

A more fulsome inclusion of MH's generation under Renewable Portfolio Standards would further enhance the value of our exports. However, despite the current limited eligibility, the inherent renewable and non-emitting natures of hydropower have been a strong marketable characteristic of MH's exports.

PUB/MH/RISK-2

Reference: **Appendix 12.1 Corporate Risk Management Report**
Risk Issue: **Market-Export Regulatory Environment A2.1**

c) Please file the definition utilized by Wisconsin for its Renewable Portfolio Standard and provide a status update on MH's efforts to have the definition to recognize large Hydro.

ANSWER:

Wisconsin Statute § 196.378 (1)(h), shown below, defines the current renewable resources recognized by the State of Wisconsin.

> (h) "Renewable resource" means any of the following:
>
> 1. A resource that derives electricity from any of the following:
>   a. A fuel cell that uses, as determined by the commission, a renewable fuel.
>   b. Tidal or wave action.
>   c. Solar thermal electric or photovoltaic energy.
>   d. Wind power.
>   e. Geothermal technology.
>   g. Biomass.
>   h. Synthetic gas created by the plasma gasification of waste.
>   i. Densified fuel pellets made from waste material that does not include garbage, as defined in s. 289.01 (9), and that contains no more than 30 percent fixed carbon.
>   j. Fuel produced by pyrolysis of organic or waste material.
>   1m. A resource with a capacity of less than 60 megawatts that derives electricity from hydroelectric power.
>
> 2. Any other resource, except a conventional resource, that the commission designates as a renewable resource in rules promulgated under sub. (4).

MH supported Wisconsin based utilities efforts to expand the definition of renewable resource to include a broader inclusion of hydroelectric generation. In 2010 a Bill was promoted within the State Senate which would have expanded the definition to include new hydro (regardless of its size). However, the bill expired with the end of legislative session without being voted upon. MH will continue to support Wisconsin based utilities efforts to expand the definition of eligible renewable resources.

PUB/MH/RISK-2

Reference: **Appendix 12.1 Corporate Risk Management Report**
Risk Issue: **Market-Export Regulatory Environment A2.1**

d) If for any reason there was a change in the Export Regulatory environment, please provide a 20 Year IFF and CEF that assumes no new export contracts other than the NSP extension and no new Northern Generation and Transmission with any domestic shortfall met through CCT generation. Please provide all supporting assumptions including annual financial targets and annualized rate increases.

ANSWER:

The work to produce an alternative IFF is complex and cannot be completed within the time allotted for responding to these Information Requests.

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PUB/MH/RISK-2

Reference: Appendix 12.1 Corporate Risk Management Report
Risk Issue: Market-Export Regulatory Environment A2.1

e) Please provide a status update on the US legislation approvals for new transmission associated with MH's term sheets.

ANSWER:

At present, the necessary facilities and their location associated with the proposed new transmission interconnection have not been determined. As a result, it is premature to define if any U.S. legislature approvals are required.

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Likelihood	Med
Consequence	High
Tolerance	Med

CATEGORY: A. Market

TITLE: 2.8 Export – Term Sheets with WPS and MP

RISK: Failure to convert WPS and MP Term Sheets into Power Sales Agreements.

DESCRIPTION:

There is a risk that the power sales envisaged in the Term Sheets with WPS and MP will not be finalized. Binding contracts are dependent on whether both companies can afford their allocation of the costs of a new major transmission line in the US.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Without a commitment by WPS and MP to funding the US portion of the major new transmission interconnection, the sales will not be feasible. Manitoba Hydro's long term operating and financial opportunities would be adversely impacted.

The preferred development sequence involving Keeyask, Conawapa and the new US interconnection would not be possible and a new development plan would have to be pursued. In the longer term, Corporate revenues would be substantially reduced, system reliability and energy supply security would be reduced, and customer rates would need to be increased.

RISK TREATMENT:

Manitoba Hydro is working closely with relevant utilities, MISO, regulatory authorities and others in the US to promote the project and include it in the 2011 MISO Transmission Expansion Plan as a Multi-Value Project with associated broad based cost socialization.

Manitoba Hydro continually assesses and maintains back-up options it can pursue in the event the preferred development plan becomes impractical.

Manitoba Hydro continues dialogue with MP and WPS and other potential purchasers who might be interested in the event that the Term Sheets with WPS and MP are not converted into Power Sales Agreements.

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HISTORICAL FLOW DATABASE

Table 1: Direct Inflow into Lake Winnipeg
Archived Hydrometric Data from Canada's Hydat Database

Primary Sources (sq. mi. x 0.386)

River System	D.A. sq. miles	Station No.	Period of Record
Red River near Lockport	110,800	050J010	1963-2008
Winnipeg River @ Slave Falls	48,600	05PF063	1907-2008
Winnipeg River @ Pine Falls	52,500	05PF069	1987-2008
Saskatchewan River @ The Pas	150,200	05KJ001	1913-2008
Saskatchewan River @ Grand Rapids	156,700	05KL001	1909-2008

Secondary Sources

River System	D.A. sq. miles	Station No.	Period of Record
Brokenhead River near Beausejour	610	05SA002	1942-2008
Fisher River near Dallas	660	05SD003	1961-2008
Fairford River near Fairford	30,800	05LM001	1912-2008
Icelandic River near Riverton	480	05SC002	1958-2008
Black River near Manigotagan	280	05RA002	1960-1992
Manigotagan River near Manigotagan	710	05RA001	1913-1996
Bloodvein River above Bloodvein Bay	3,510	05R3003	1976-2008
Pigeon River @ Outlet on Round Lake	7,100	05RD008	1957-1996
Berens River above Berens Lake	2,210	05RC001	1980-2008
Berens River @ Outlet of Long Lake	7,100	05RD007	1958-1992
Poplar River @ Outlet of Weaver Lake	2,640	05RE001	1967-1996
Gunisao River @ Jam Rapids	1,780	05UA003	1971-2007

Table 2: Direct Inflow into Lower Nelson River
Archived Hydrometric Data from Canada's Hydat Database

Primary Sources

River System	D.A. sq. miles	Station No.	Period of Record
Nelson River above Bladder Rapids	401,400	050D004	1958-1994
Nelson River @ Kelsey G.S.	405,300	050E005	1960-2008
Burntwood River near Thompson	7,100	05TG001	1957-2007
Nelson River @ Kettle G.S. (not including CRD)	424,600	050F006	1982-2008
Churchill River @ Leaf Rapids	94,200	06E003	1973-2007

Secondary Sources

River System	D.A. sq. miles	Station No.	Period of Record
Grass River @ Wekusko Falls	1,260	05TB002	1957-1991
Odei River near Thompson	2,460	05TG003	1979-2008

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Restatement of PUB/MH I-79(D)

Apr. 1st EIS (1,000 GWh)	Year	Annual Hydraulic Generation (GWh)	Precipitation for Total Watershed (mean)							
			Winter Prior Oct. to Feb	% of Average	Spring Mar/Apr.	% of Average	Winter & Spring	% of Average	Summer May-Sept.	% of Average
6.5	1978/79	31,000	--		60.3	110	--		382.3	105
9.2	1979/80	31,000	133.1		80.7		218.8	109	297.1	81
9.8	1980/81	25,100(8)	150.3	104	32.7	60	183.0	91	365.4	100
6.0	1981/82	22,200(3)	114.6	79	52.9	99	167.5	84	324.3	89
3.7	1982/83	29,800	150.7	104	59.3	110	210.0	105	368.3	101
7.6	1983/84	28,000	147.9	102	54.2	100	212.1	106	347.2	95
7.0	1984/85	26,000	142.5	99	48.0		190.5	85	332.7	91
5.6	1985/86	33,000	180.9		68.6		249.5	125	416.1	114
10.7	1986/87	33,000	135.1		85.9		221.0	110	375.6	103
8.7	1987/88	22,400(4)	116.8	81	39.6	73	156.4	78	318.9	87
4.8	1988/89	18,900(2)	104.5	72	61.1	113	170.6	85	363.7	100
4.6	1989/90	24,300(7)	144.2	100	44.3	82	188.5	94	344.9	95
4.5	1990/91	24,200(6)	130.5	90	71.2	131	201.7	101	329.6	90
3.8	1991/92	24,000(5)	140.5	97	69.2	128	209.7	105	413.4	113
6.8	1992/93	28,800	155.5		55.6	101	211.7	106	378.3	104
8.1	1993/94	28,200	100.3	69	48.6	90	148.9	74	413.9	113
8.3	1994/95	28,200	108.1	75	47.6	88	155.7	78	344.7	95
8.6	1995/96	29,400	160.0		48.9	90	208.9	104	349.5	96
8.3	1996/97	30,200	165.9		54.0	100	209.9	105	357.0	98
11.1	1997/98	37,500	183.5		55.4	161	238.9	119	339.2	93
12.3	1998/99	29,000	146.4	100	36.2	67	182.6	91	326.7	90
7.2	1999/00	28,800	150.9	103	36.2	67	187.1	94	430.5	118
9.2	2000/01	30,600	118.1		55.1	101	173.2	87	400.1	110
9.3	2001/02	31,000	127.6		69.5		197.1	99	340.1	93
6.3	2002/03	28,100	117.0		70.1		187.1	94	380.6	104
4.2	2003/04	18,500(1)	91.7	63	58.8	109	150.5	75	338.8	93
6.0	2004/05	31,100	123.9		62.5	110	186.4	93	394.6	108
11.8	2005/06	37,200	173.3		54.1	100	227.4	114	368.5	101
12.4	2006/07	31,600	154.6	107	48.8	90	203.4	102	319.0	87
8.3	2007/08	34,800	134.3		63.5	110	197.8	99	387.0	106
11.4	2008/09	34,200	162.1		59.3		221.9	111	371.1	102
11.1	2009/10	33,800	149.6		72.7		222.3	111	348.5	95
	2010/11	--	112.2		--		--		--	

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PUB/MH/RISK-74

Reference: **KPMG Report – Main Report/End of May 2010 MH Workshop**
Risk Issue: **MH Workshop**

d) **Please explain why KPMG (or MH) did not do a model verification run employing the actual drought event data (GWh/¢/KWh/etc.) for the 2002/03 and 2003/04 period.**

ANSWER:

KPMG was not asked to do a model verification run for 2002-2004 as it was prior to the initial NYC engagement. KPMG reviewed Manitoba Hydro's drought management strategies, the validity of its models and forecasting technique. The results of that review found:

- Manitoba Hydro's process for forecasting water flow is reasonable; the process is statistically sound and is a standard industry approach.
- The use of historical water flow data for forecasting is reasonable.
- Manitoba Hydro has taken appropriate care and due diligence in developing, operating and maintaining the models.

Manitoba Hydro's drought management strategies, models and forecasting technique were all in place in 2002-2004 and testing them against that specific year with perfect hindsight with regard to prices would not have changed the conclusions.

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Current System Capability

Fiscal Year Beginning	April 1st E.I.S. (TWh)	Maximum Annual E.I.S. (TWh)	E.I.S. INFLOW to Peak (TWh)	E.I.S. Outflow to Year End (TWh)	Evaporation Losses (inches)
1978	6.5	19.0	12.5	9.8	16"
1979	9.2	20.8	11.6	12.0	14"
1980	9.8	13.6	4.8	7.6	**22"**
1981	6.0	12.8	6.8	9.1	15"
1982	3.7	16.7	13.0	9.1	16"
1983	7.6	16.5	8.9	9.5	15"
1984	7.0	15.4	8.4	9.8	9"
1985	5.6	19.1	13.5	8.4	8"
1986	10.7	19.1	8.4	10.4	12"
1987	8.7	14.2	5.5	9.4	14"
1988	4.8	10.1	5.7	5.5	**24"**
1989	4.6	13.5	8.9	9.0	16"
1990	4.5	16.3	11.5	12.5	**18"**
1991	3.8	12.6	8.8	5.8	12"
1992	6.8	17.6	10.8	9.5	13"
1993	8.1	17.4	9.3	9.1	6"
1994	8.3	15.9	7.6	7.3	4"
1995	8.6	15.8	7.2	7.5	14"
1996	8.3	20.3	12.0	9.2	4"
1997	11.1	20.7	9.6	8.5	14"
1998	12.3	18.2	5.9	11.0	9"
1999	7.2	16.8	9.6	7.6	10"
2000	9.2	17.3	8.1	8.0	4"
2001	9.3	18.7	9.4	12.4	10"
2002	6.3	15.2	8.9	11.0	14"
2003	4.2	7.5	3.3	1.5	**18"**
2004	6.0	18.0	12.0	6.2	2"
2005	11.8	24.0	12.2	11.6	5"
2006	12.4	18.5	6.1	10.2	**23"**
2007	8.3	20.8	12.5	9.4	13"
2008	11.4	20.2	8.8	9.1	
2009	11.1	20.2	9.1	9.7	
2010	10.5	19.5 July 8/10 20.0 Sept/10			

PUB/MH I-82(e)

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PUB/MH/RISK-32

Reference: PUB/MH II-75; PUB/MH II-90
Risk Issue: Drought Frequency

a) **Please confirm that the data in the following table reasonably represents information filed in PUB/MH II-75, PUB/MH II-90, and PUB/MH II-82, with the exception of the last column, which is drawn from other sources.**

Year	April 1st Energy-in Storage (GWh)	Total Potential Hydraulic Generation (GWh)	Total Nelson River Flow (cfs)	Red River Flow (cfs)	Winnipeg River Flow (cfs)	Winnipeg River No. of Months Flow <20,000 cfs	Accumulated Summer (Theoretical) (Net) Evaporation Loss on Lake Winnipeg
1980-81	9,800	25,210	97,500	2,900	21,000	6	22"
1981-82	6,000	22,201	81,100	2,500	18,000	7	15"
1982-83	3,700	29,800	106,900	8,000	35,100	4	16"
1987-88	8,700	22,353	94,100	5,900	15,200	8	14"
1988-89	4,800	18,850	73,900	1,900	19,700	6	24"
1989-90	4,600	24,274	90,000	4,000	32,100	1	16"
1990-91	4,500	24,162	89,500	2,400	24,300	4	18"
1991-92	3,800	24,658	88,600	3,600	25,700	0	12"
1994-95	8,300	28,200	103,900	10,000	34,100	2	4"
1998-99	12,300	29,000	115,800	11,400	19,500	5	9"
2003-04	4,200	18,500	66,400	5,100	18,100	8	18"
2006-07	12,400	31,200	132,900	12,400	22,200	10	23"
1977-2009 Average	8,000	29,000±	106,000	9,600	32,300	N/A	12"

ANSWER:

Manitoba Hydro confirms the accuracy of the information provided in response to PUB/MH II-75, PUB/MH II-90, and PUB/MH II-82. However the information contained in this table does not relate to the responses filed for PUB/MH II-75, PUB/MH II-82 or PUB/MH-II-90.

Manitoba Hydro can confirm the following regarding the information provided in this table:

1. "April 1st [*Potential*] Energy in Reservoir Storage (GWh)" values shown in the table are in agreement with Manitoba Hydro records and the response filed for PUB/MH I-82(e).

2. "Total Potential Hydraulic Generation (GWh)" values that are shaded in the table agree with the values provided in the response filed for PUB/MH I-90(b). Manitoba Hydro has not performed similar calculations for the non-shaded values.

3. Manitoba Hydro provided monthly Lower Nelson River flow at Kettle from 1978-2008 in the response to PUB/MH I-75 and confirms the accuracy of that response. The information provided in that response is representative of total Nelson River flows. Average "Total Nelson River Flow (cfs)" values in the above table generally agree with Manitoba Hydro records, with the exception of 1981-82. Manitoba Hydro records indicate annual average flows for 1981-82 were approximately 87,000 cfs (not 81,100 cfs).

4. Manitoba Hydro provided monthly Red River flow for 1978-2005 in the response to PUB/MH I-75 and confirms the accuracy of that response. Average "Red River Flow (cfs)" values in the above table generally agree with Manitoba Hydro records.

5. Manitoba Hydro provided monthly Winnipeg River flow at Slave Falls for 1978-2008 in the response to PUB/MH I-75 and confirms the accuracy of that response. Average "Winnipeg River Flow (cfs)" values in the above table generally agree with Manitoba Hydro records.

6. Manitoba Hydro provided monthly Winnipeg River flow at Slave Falls for 1978-2008 in the response to PUB/MH I-75 and confirms the accuracy of that response. A count of "Winnipeg River No. of Months of Flow <20,000 cfs" was calculated from the information provided in PUB/MH I-75. The results of this count are provided in Table 1 below.

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Table 1.

Year	Winnipeg River No. of Months Flow <20,000 cfs
1980-81	6
1981-82	6
1982-83	0
1987-88	9
1988-89	6
1989-90	1
1990-91	3
1991-92	2
1994-95	2
1998-99	5
2003-04	8
2006-07	7

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Year	April		Peak		October	
	E.I.S. (1,000 GWh)	Lake Winnipeg	E.I.S. (1,000 GWh)	Lake Winnipeg	E.I.S. (1,000 GWh)	Lake Winnipeg
87/88	8.7	713.4	14.2	715.2		713.0
88/89	<u>4.8</u>	711.9	10.1	712.4		711.5
89/90	<u>4.6</u>	711.8	13.5	713.1		712.4
90/91	<u>4.5</u>	711.9	16.3	713.8		713.0
91/92	<u>3.8</u>	712.0	12.6	712.6		711.9
92/93	<u>6.8</u>	712.1	17.6	714.5		714.4
93/94	8.1	713.0	17.4	714.6		714.2
94/95	8.3	713.8	15.9	714.1		713.3
95/96	8.6	713.4	15.8	714.0		713.1
96/97	8.3	713.0	20.3	714.7		713.6
97/98	11.1	713.9	20.7	715.3		714.3
98/99	12.3	714.0	18.2	714.6		714.3
99/00	7.2	712.6	16.8	714.1		713.5
00/01	9.2	713.2	17.3	714.5		713.8
01/02	9.3	713.4	18.7	714.7		713.7
02/03	<u>6.3</u>	712.2	15.2	713.9	14.0	713.2
03/04	<u>4.2</u>	712.1	7.5	712.0	8.0	711.6
04/05	<u>6.0</u>	712.4	18.0	714.5	18.0	714.5
05/06	11.8	714.5	24.0	716.2	20.0	714.6
06/07	12.4	714.3	18.5	714.6	14.0	712.9
07/08	8.3	712.6	20.8	714.7	17.5	713.7
08/09	11.4	713.8	20.2	714.8	17.5	714.3
09/10	11.1	713.8	20.2	715.5	18.0	714.5
10/11	10.5	713.7	20.0	715.6	?	715.3

PUB/MIH I-82 (e)
VARIOUS EIS CURVES
L. WPG WATER LEVEL @ BERENS RIVER.

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PUB/MH II-208

Reference: PUB/MH I-209/IFF 09-1 Revenue & Cost Assumptions

b) Please confirm that MH anticipated the combined effect of natural gas prices and carbon adders could support average unit prices as follows:

	High Prices		Expected Prices		Low Prices	
	Export ¢/KWh	Import ¢/KWh	Export ¢/KWh	Import ¢/KWh	Export ¢/KWh	Import ¢/KWh
2009/10	3.62	5.32	3.62	5.32	3.62	5.32
2010/11	4.10	3.86	4.10	3.86	4.10	3.86
2011/12	8.55	7.70	6.59	6.53	5.61	5.98
2012/13	8.75	7.98	6.59	6.68	5.61	6.10
2014/15	9.59	8.17	7.17	6.91	5.98	6.34
2019/20	14.01	9.39	10.60	7.05	8.44	6.43
2024/25	15.39	11.23	11.94	9.61	9.44	7.37
2029/30	18.71	11.80	13.86	9.48	10.05	7.64

ANSWER:

Manitoba Hydro does not accept that only natural gas prices and carbon adders comprise average unit prices for imports and exports. There are many factors that affect the price of export sales and cost for import energy that Manitoba Hydro experiences. As explained in the response to question PUB/MH I-156(a):

> "In preparing their forecasts, the consultants prepare their own internal estimates for a number of pricing factors. These pricing factors include, but are not limited to, thermal fuel forecasts (coal and natural gas), future load growth forecasts, capital costs and required rates of return, generation retirements and additions, power market rules, future legislative regulations including greenhouse gases, SOx, NOx, and mercury and renewable portfolio standard requirements, and characteristics of the existing generation fleet. Hence, any CO2 premium is but one of many pricing factors considered in developing the electricity export price forecast."

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The above discussion confirms that natural gas price and carbon adders are two of the many factors that influence the unit prices in the table that is provided in the information request. Manitoba Hydro has the following comments on the summarized information provided in the table in this information request which appears to be derived from the response to PUB/MH I-209. Manitoba Hydro is able to verify many of the unit prices as part of the information provided in PUB/MH I-209, however there are also many errors in the table provided in the information request. The correct unit prices have been inserted into a revised table that is provided below with the revised unit prices shown in red, italic format and the hatched border style.

	High Prices		**Expected Prices**		**Low Prices**	
	Export ¢/KWh	**Import ¢/KWh**	**Export ¢/KWh**	**Import ¢/KWh**	**Export ¢/KWh**	**Import ¢/KWh**
2009/10	3.62	5.32	3.62	5.32	3.62	5.32
2010/11	4.10	3.86	4.10	3.86	4.10	3.86
2011/12	8.55	*7.56*	6.59	6.53	5.61	5.98
2012/13	*8.76*	7.70	*6.69*	6.68	5.61	6.10
2014/15	*9.69*	8.17	*7.39*	*7.05*	*6.13*	6.34
2019/20	14.01	9.39	*10.56*	*7.62*	8.44	6.43
2024/25	15.39	11.23	11.94	*9.01*	9.44	7.37
2029/30	18.71	11.80	13.86	9.48	10.05	7.64

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PUB/MH II-208

Reference: PUB/MH I-209/IFF 09-1 Revenue & Cost Assumptions

c) Please explain the logic behind the increase in the spread (divergence) of export and import prices after 2014/15:

- **High price scenario - 1.5¢/KWh differential going to 7¢/KWh.**
- **Expected price scenario - 0.5¢/KWh differential going to 4¢/KWh.**
- **Low price scenario - minus 0.5¢/KWh differential going to 2.5¢/KWh.**

ANSWER:

The increased spread between import and export prices begins to occur after 2018/19 which is the date of the new interconnection to the U.S. that is associated with the export sales to MP and WPS. The increased spread is not due to a divergence in the forecasted market prices of the export and import energy; rather it is due to the characteristics of Manitoba Hydro's ability to participate in the electricity export and import market.

Manitoba Hydro does not assume that there is a single price for export and import energy in each on-peak and off-peak period. Instead, a price structure is defined separately for exports and imports, which represents the variability of prices over the hours of the month and Manitoba Hydro's limited ability to access the market through the use of interconnections. The reason for the increased spread between import and export prices after 2018/19 is that the new interconnection to the U.S. allows more export energy to be sold at higher prices, thus increasing the average price of export energy after 2018/19. Similarly, the new interconnection increases the capability to import more low priced energy and this has the effect of decreasing the average price of imports after 2018/19. The combined effects of increased export prices and reduced import costs results in the increased spread which begins to occur after 2018/19.

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TAB 11

MANITOBA HYDRO
2010/11 & 2011/12 RATE INCREASE APPLICATION

COST OF SERVICE STUDY

INDEX

MANITOBA HYDRO
2010/11 & 2011/12 GENERAL RATE APPLICATION

COST OF SERVICE STUDY

11.0 OVERVIEW

Tab 11 includes a summary discussion and results of Manitoba Hydro's Cost of Service Study ("COSS"). This section includes a description of the cost study filed and the methodology used to prepare the study.

Appendix 11.1 is the Prospective Cost of Service Study for the 2009/10 fiscal year ("PCOSS10") which is based on IFF08-1.

Appendix 11.2 is the Allocation Program that provides a complete list of the allocation tables and the allocated costs for each rate class by cost component as used in PCOSS10.

Manitoba Hydro intends to file a Prospective Cost of Service Study for the 2010/11 fiscal year ("PCOSS11") as soon as it can be prepared and finalized, likely in late January, 2010.

11.1 BACKGROUND

After the 2006 Cost of Service review and the 2008 General Rate Application the Public Utilities Board ("PUB") issued Orders 117/06 and 116/08 which directed changes to the COS methodology. In March 2009, Manitoba Hydro filed a 2008 Cost of Service Study that reflected these directives. The results filed with the PUB in March are included in this Application as Appendix 11.3.

Manitoba Hydro supports most, but not all, the Cost of Service Study directives in these Orders. Manitoba Hydro continues to have concerns that the results under the directed methodology cannot be relied on as class revenue requirement benchmarks or for rate design and other internal uses of the PCOSS. The 2010 Prospective Study incorporates most but not all of the cost of service directives in Orders 117/06 and 116/08. The methodology used has varied from the PUB directives to reduce complexity and improve

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depiction of cost causation, primarily in areas related to costs assigned to the Export class.

Manitoba Hydro intends to engage external consulting services to review the Cost of Service methodology for consistency with cost causation, utility economics and the range of regulatory practice in North America and, pursuant to that review, to make appropriate recommendations with respect to either maintaining or varying those methodologies. Manitoba Hydro will file its Terms of Reference in January, 2010.

Because the current Rate Application is being filed on an across-the-board basis and because the COS methodology will be subjected to an external review process, it is recommended that the PCOSS10 and the PCOSS11 be accepted for information only at this time.

11.2 PCOSS10 METHODOLOGY

The key features of the methodology used in PCOSS10 are listed below and, other than the treatment of Export Revenues, are consistent with directives provided by the PUB in Orders 117/06 and 116/08. Details are provided in Appendix 11.1.

1. Functionalization: Manitoba Hydro costs are placed into five main functions: Generation; Transmission; Subtransmission; Distribution Plant; Distribution Services.

2. Classification and Allocation of Generation Costs: Embedded Generation costs are classified as Energy related and allocated among customer classes and exports on the basis of Energy use weighted by time-differentiated marginal cost. Time differentiated marginal cost is expressed by daily Surplus Energy Program prices summarized into four seasons and three time-of-day periods.

3. Classification and Allocation of Transmission Costs: Transmission costs are classified as demand-related and allocated on the basis of class contribution to Summer Peak (top 50 hours) and Winter Peak (top 50 hours).

4. Classification and Allocation of Subtransmission Costs: Subtransmission costs are classified as 100% demand-related and allocated on basis of Class Non-Coincident Peaks.

5. Classification and Allocation of Distribution Plant Costs: Distribution Plant is classified between customer and demand, with different classification ratios for the sub-functions (e.g.: poles & wire; line transformers). Demand-related costs allocated on the basis of class Non-Coincident Peak; Customer-related costs on weighted customer count.

6. Classification and Allocation of Distribution Services Costs: Distribution Services classified as Customer-related with different weightings for the allocation of various sub-functions (e.g.: customer service; billing and collections).

7. Treatment of Export Revenues and Costs: PCOSS10 includes a single export class that is allocated Generation and Transmission costs on the same basis as to domestic customers. Manitoba Hydro continues to believe that consideration should still be given to separate Opportunity and Dependable Export classes and this is one option that will be further considered in the upcoming external review of the COSS.

Purchased power costs and the costs associated with securing US transmission used to make opportunity export sales have been directly assigned to the Export class as directed in Order 116/08. Other costs assigned to the Export class are limited to those that Manitoba Hydro believes can be justified on the basis of cost causation.

Since gas-fired generation is almost never used to support exports, PCOSS10 assigns the cost of gas-fired thermal plants entirely to the domestic classes who benefit from the dispatchable energy provided by these plants. In PCOSS10, fuel and variable maintenance costs for Brandon Unit 5, other than that related to operation necessary for staff proficiency training and reliability runs, have been assigned to the Export class. The remaining costs have been allocated to the domestic classes. PCOSS11 will assign all costs of Brandon Unit 5 to the domestic classes to recognize the restrictions on operation after December 31, 2009 as a result of Bill 15.

The 'Trading Desk', as well as MISO and MAPP memberships, provides benefits to domestic customers by facilitating import purchases needed for dependable supply, during periods of prolonged drought, or in the event of a major generation or transmission failure. Consequently, only the portion of these costs that can be directly attributed to Manitoba Hydro's export sales activities has been directly assigned to the export class, with the remaining assigned to the domestic classes.

DSM costs are assigned to the customer classes benefiting from the DSM programming, in the same manner as carried out prior to PCOSS08. This process reasonably assigns costs in accordance with the classes which benefit from the expenditures, is relatively simple to carry out, and avoids methodological complications associated with tracking cumulative DSM energy and capacity savings as directed in Order 116/08. The costs of programs that are funded by the Affordable Energy Fund have been charged directly to the Export class in this study, consistent with the PUB directives.

PCOSS10 employs Manitoba Hydro's forecast of export prices for 2009/10 as used in its Integrated Financial Forecast ("IFF") that underlies the PCOSS, and which supports Manitoba Hydro's rate requests to the PUB. If the most recent actual export prices were used as the basis for the IFF in the current year, the rate increase requirements would be increased relative to using Manitoba Hydro's forecast. Since the PCOSS is based on median flows, it is incorrect to apply lower average unit prices from a year of above average flows, with predominantly opportunity sales, against sales volumes under median flow conditions.

11.3 PCOSS10 RESULTS AND COMPARISON TO PCOSS08

Table 11.1 summarizes the Revenue Cost Ratio ("RCC") results of the 2009/10 Prospective Cost of Service Study for the major rate classes in the context of current rates.

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Table 11.1 - Results of Prospective 2009/10 Cost of Service Study
Class RCC Ratios

Class	PCOSS10 RCC	PCOSS10 RCC (Pre-Exports)[1]	PCOSS08 RCC (116/08)[2]
Residential	96.4%	86.7%	96.2%
General Service:			
Small Non-Demand	105.7%	96.3%	101.4%
Small Demand	102.8%	93.4%	107.8%
Medium	101.3%	91.9%	100.2%
Large < 30 kV	92.3%	82.9%	89.9%
Large 30-100 kV	106.8%	97.1%	108.4%
Large >100 kV	109.2%	99.6%	112.0%
Area and Roadway Lighting	100.0%	96.8%	102.4%

1 RCC shown is prior to the allocation of Net Export Revenue
2 Version of PCOSS08 reflects Cost of Service related Directives per Orders 116/08 and 117/06, as submitted to the PUB in March, 2009.

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COSS

PCOSS COMPARISONS

	PCOSS-11	PCOSS-10	March 2009 PCOSS-08	August 2007 PCOSS-08
Gross Export Revenue and Sales	$384 M (7,122 GWh) 5.39¢/KWh	$546 M (7,707 GWh) 7.08¢/KWh	$475 M (7,707 GWh) 6.16¢/KWh	$552 M (8,462 GWh) 6.52¢/KWh
Uniform Rates AEF Expenditures	$20 M $12 M	$19 M $4 M	$17 M $23 M (DSM)	$17 M $25 M (DSM)
Trading Desk MISO/MAPP NEB Cost	$5 M $2 M $1 M	$5 M $2 M $2 M	$13 M $7 M	$13 M $7 M
Purchased Power and Transmission Allocated Water Rentals Allocated G&T Brandon Unit 5 & Other Thermal Fuels	$120 M $21 M $156 M} $177 M Nil	$174 M $23 M $177 M} $200 M $14 M	$140 M } $174 M $52 M	$134 M } $167 M $23 M
Total Assigned	**$297 M**	**$388 M**	**$426 M**	**$385 M**
Net Export Revenue	$47 M	$126 M	$49 M	$165 M
Gross Domestic Revenue and Sales	$1,210 M (21,054 GWh) 5.75¢/KWh	$1,199 M (21,738 GWh) 5.51¢/KWh	$1,069 M 20,815 GWh 5.14¢/KWh	$1,069 M 20,815 GWh 5.14¢/KWh

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COSS (Cont'd)

PCOSS COMPARISONS

		PCOSS-11	PCOSS-10	March 3/2009 PCOSS-08	August 2007 PCOSS-08
Total Costs		$1,599 M	$1,750 M	$1,549 M	$1,624 M
Domestic Service		$1,250 M	$1,317 M	$1,111 M	$1,232 M
Diesel		$12 M	$13 M	$11 M	$6 M
Exports		$337 M	$420 M	$426 M	$387 M
Generation & Transmission	Domestic	$767 M (3.64¢/KWh)	$828 M ($3.81¢/KWh)	$645 M (3.2¢/KWh)	$980 M (4.71¢/KWh)
	Diesel	$12 M	$13 M	$12 M	$12 M
Exports					
- Assigned		$160 M (2.26¢/KWh)	$220 M (2.85¢/KWh)	$252 M (3.29¢/KWh)	$220 M (2.60¢/KWh)
- Allocated		$177 M (2.49¢/KWh)	$200 M (2.60¢/KWh)	$174 M (2.26¢/KWh)	$167 M (1.97¢/KWh)
Total G&T		**$1,116 M**	**$1,261 M**	**$1,087 M**	**$1,166 M**
Subtransmission	Domestic	$75 M	$83 M		$77 M
Distribution Plant	Domestic	$311 M	$313 M		$299 M
Distribution Service	Domestic	$97 M	$489 M		$84 M
		$483 M (2.29¢/KWh)	$489 M (2.25¢/KWh)	$417 M (2.0¢/KWh)	$460 M (2.21¢/KWh)

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COSS (Cont'd)

BULK POWER – EXPORT ALLOCATION OF GENERATION COSTS

		August 2007 PCOSS 08	March 2009 PCOSS 08	November 2009 PCOSS 10	May 2010 PCOSS 11
Includes: • HVDC Lines • Northern Converters • AC Connectors • Water Rentals	Hydraulic Generation	$116 M (19%)	$129 M	$200 M (30%)	$170 M (27%)
	- Unweighted	4,524/28,265 (16%)			6,249/30,310 (21%)
	- SEP Weighted	9,787/62,480 (16%)			14,928/72,362 (21%)
	Thermal Generation	$23 M (68%)	$52 M (_%)	$14 M (40%)	Ø (0%)
	Coal (Brandon)	Ø Fixed 100% Fuel	50% Fixed 100% Fuel	Ø Fixed 100% Fuel & Variable O&M	Ø Fixed Ø Fuel Ø O&M
	Natural Gas (Brandon & Selkirk)	Ø Fixed 100% Fuel	50% Fixed 100% Fuel	Ø Fixed Ø Variable	Ø Fixed Ø Variable
Imports & Wind	Purchased Power	$134 M (100%)	$140 M (100%)	$174 M (100%)	$120 M (100%)
	Trading Desk MISO/NEB	$20 M (100%)	$20 M (100%)	$9 M (42%)	$8 M (42%)
	Generation Total	**$298 M (31%)**	**$364 M (40%)**	**$388 M (36%)**	**$297 M (32%)**
Other Obligations	Uniform Rates	$17 M	$17 M	$19 M	$20 M
	Affordable Energy	--	--	$4 M	$12 M

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COSS (Cont'd)

BULK POWER – EXPORT ALLOCATION OF TRANSMISSION COSTS

		August 2007 PCOSS 08	March 2009 PCOSS 08	November 2009 PCOSS 10	May 2010 PCOSS 11
	Northern Converter(s)	Ø	Ø	Ø	Ø
	HVDC Lines (Bipole I & II)	Ø	Ø	Ø	Ø
	Southern Converter(s)	?	?	?	?
	Stations	?	?	?	?
	AC Lines	?	?	?	?
	AC Border Connections	?	?	?	?
	Transmission Total	**$51 M/194 (26%)**	**$45 M/204 (22%)**	**$56 M/190 (30%)**	**$48 M/197 (24%)**
SYSTEM USAGE BY EXPORTS					
	Winter Peak Export	753 MW 4,418 (17%)	__ MW	__ MW	826 MW 4,412 (18.7%)
PCOSS 11 Schedule D-1	Summer Peak Export	1,227 MW 3,961 (31%)	__ MW	__ MW	1,280 MW 3,883 (33%)
	2 CP	990 GWh 4,190 (23.6%)	__ GWh	__ GWh	1,053 GWh 4,148 (25.4%)
	Winter Energy	2,904 GWh 16,556 (17.5%)	__ GWh	__ GWh	3,409 GWh 16,839 (20%)
PCOSS 08 Schedule D-1	Summer Energy	4,700 GWh 15,266 (31%)	__ GWh	__ GWh	5,053 GWh 15,361 (33%)
	Annual Energy	7,604 GWh 31,822 (24%)	__ GWh	__ GWh	8,462 GWh 32,200 (26%)

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Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2011
Revenue Cost Coverage Analysis

SUMMARY

Customer Class	Total Cost ($000)	Class Revenue ($000)	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates
Residential	540,365	497,455	20,535	517,990	95.9%
General Service - Small Non Demand	118,628	119,914	4,383	124,297	104.8%
General Service - Small Demand	114,981	115,086	4,217	119,303	103.8%
General Service - Medium	168,455	164,114	6,237	170,352	101.1%
General Service - Large 0 - 30kV	80,204	70,730	2,964	73,694	91.9%
General Service - Large 30-100kV*	32,915	33,070	1,241	34,311	104.2%
General Service - Large >100kV*	173,341	188,679	6,499	195,178	112.6%
*Includes Curtailment Customers					
SEP	1,006	852	-	852	84.7%
Area & Roadway Lighting	19,574	20,339	259	20,598	105.2%
Total General Consumers	1,249,469	1,210,239	46,336	1,256,574	100.6%
Diesel	12,375	4,793	477	5,270	42.6%
Export	337,251	384,064	(46,813)	337,251	100.0%
Total System	1,599,096	1,599,096	-	1,599,096	100.0%

APPENDIX 58

SCHEDULE B1
Revenue Cost Coverage Analysis

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2011
Customer, Demand, Energy Cost Analysis

SUMMARY

	CUSTOMER			DEMAND				ENERGY		
Class	Cost ($000)	Number of Customers	Unit Cost $/Month	Cost ($000)	% Recovery	Billable Demand MVA	Unit Cost $/KVA	Cost ($000)	Metered Energy mWh	Unit Cost ¢/kWh
Residential	121,464	470,975	21.49	201,202	0%	n/a	n/a	197,163	6,771,781	5.88 **
GS Small - Non Demand	23,721	53,170	37.18	41,769	0%	n/a	n/a	48,756	1,571,227	5.76 **
GS Small - Demand	7,335	11,451	53.38	46,112	38%	2,100	8.34	57,316	1,883,200	4.56
General Service - Medium	6,325	1,867	282.36	67,099	87%	6,978	8.40	88,794	3,015,078	3.23
General Service - Large <30kV	3,153	259	n/a	29,553	100%	3,646	8.97 *	44,535	1,538,688	2.89
General Service - Large 30-100kV	2,156	30	n/a	7,597	100%	1,681	5.80 *	21,921	846,683	2.59
General Service - Large >100kV	2,231	14	n/a	29,035	100%	8,969	3.49 *	135,576	5,310,790	2.55
SEP	261	23	946.48	159	0%	n/a	n/a	587	15,200	4.90 **
Area & Roadway Lighting	14,342	154,961	7.71	2,664	0%	n/a	n/a	2,309	101,099	4.92 **
Total General Consumers	180,988	692,750		425,189		23,374		596,956	21,053,746	
Diesel	273	760	29.91	409	0%	n/a	n/a	11,217	13,664	85.08 **
Export	n/a	n/a	n/a	46,327	0%	n/a	n/a	290,925	7,122,000	4.74 ***
Total System	181,261	693,510		471,925		23,374		899,098	28,189,411	

* - includes recovery of customer costs
** - includes recovery of demand costs
*** -includes recovery of customer and demand costs

APPENDIX 58

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2011
Functional Breakdown

SUMMARY

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	519,830	197,163	37.9%	49,565	9.5%	37,259	7.2%	60,599	11.7%	175,243	33.7%
General Service - Small Non Demand	114,246	48,756	42.7%	12,186	10.7%	7,288	6.4%	15,902	13.9%	30,114	26.4%
General Service - Small Demand	110,763	57,316	51.7%	13,460	12.2%	8,023	7.2%	3,538	3.2%	28,426	25.7%
General Service - Medium	162,218	88,794	54.7%	21,331	13.1%	11,246	6.9%	5,411	3.3%	35,437	21.8%
General Service - Large <30kV	77,240	44,535	57.7%	10,610	13.7%	5,317	6.9%	2,945	3.8%	13,833	17.9%
General Service - Large 30-100kV	31,674	21,921	69.2%	4,927	15.6%	2,670	8.4%	2,111	6.7%	44	0.1%
General Service - Large >100kV	166,842	135,576	81.3%	29,035	17.4%	0	0.0%	2,209	1.3%	21	0.0%
SEP	1,006	587	58.3%	159	15.8%	0	0.0%	248	24.6%	13	1.3%
Area & Roadway Lighting	19,315	2,369	12.3%	415	2.1%	570	3.0%	608	3.1%	15,353	79.5%
Total General Consumers	1,203,134	597,017	49.6%	141,688	11.8%	72,373	6.0%	93,572	7.8%	298,484	24.8%
Diesel	11,898	11,217	94.3%	0	0.0%	0	0.0%	0	0.0%	682	5.7%
Export	337,251	290,925	86.3%	46,327	13.7%	0	0.0%	0	0.0%	0	0.0%
Total System	1,552,283	899,158	57.9%	188,014	12.1%	72,373	4.7%	93,572	6.0%	299,166	19.3%

APPENDIX 5B

PUB/MH II-45

Subject: **Tab 5: Integrated Financial Forecast**
Reference: **PUB/MH I-45 (b) Assumptions**

a) Please provide an expanded table including export transmission losses and all assumptions to 2029.

ANSWER:

Please see attached table.

Transmission charges are netted to export sales for the purposes of the average price calculation. Merchant sales and purchases are excluded from the calculation.

IFF09 Export Revenue Assumptions

(in GWh)	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
MH Hydraulic Generation	33,124	30,525	30,067	30,789	30,989	30,913	30,929	31,078	30,812	30,755	33,518
MH Thermal Generation	152	159	432	437	441	444	497	531	580	591	521
Import Energy (including Wind)	733	1,508	2,616	2,576	2,569	2,608	2,663	2,717	2,794	3,789	3,459
Manitoba Domestic Energy Sales	23,968	24,346	24,728	25,075	25,413	26,030	26,439	26,790	26,743	26,929	27,229
Total Export Sales	9,149	7,122	7,841	8,150	8,020	7,430	7,181	7,082	7,006	7,746	9,598
Export Transmission Losses	891	724	546	577	566	504	469	454	438	461	670
Total Supply	34,009	32,192	33,114	33,802	33,998	33,964	34,089	34,326	34,186	35,136	37,497
Total Demand	34,008	32,192	33,114	33,802	33,998	33,964	34,089	34,326	34,186	35,136	37,497

(in Millions of Dollars)	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
MH Hydraulic Generation	$ 111	$ 102	$ 100	$ 103	$ 104	$ 103	$ 103	$ 104	$ 103	$ 103	$ 112
MH Thermal Generation	8	8	41	41	44	45	55	61	70	75	77
Import Energy (including Wind)	36	56	171	172	177	184	195	206	217	289	264
Total Manitoba Domestic Energy Sales	1,160	1,193	1,246	1,305	1,365	1,441	1,510	1,582	1,653	1,725	1,805
Total Export Sales	332	292	517	545	575	549	653	654	665	816	1,013

Average Price ($/MWh)	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
MH Hydraulic Generation	$ 3.36	$ 3.35	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation	52.79	52.09	95.96	94.72	99.73	102.53	109.86	115.37	120.73	127.24	147.20
Import Energy (including Wind)	49.69	37.12	65.29	66.78	69.08	70.54	73.36	75.75	77.65	76.20	76.21
Total Manitoba Domestic Energy Sales	48.40	48.99	50.39	52.03	53.69	55.36	57.13	59.05	61.80	64.07	66.30
Total Export Sales	36.24	41.02	65.92	66.90	71.73	73.96	90.88	92.33	94.97	105.33	105.58

IFF10 Export Revenue Assumptions

(in GWh)	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
MH Hydraulic Generation	34,066	31,360	30,632	30,801	30,747	30,755	30,772	30,588	30,543	30,648
MH Thermal Generation	80	89	413	410	391	379	390	424	437	206
Import Energy (including Wind)	1,686	2,972	2,054	2,130	2,153	2,173	2,247	2,265	2,309	3,400
Manitoba Domestic Energy Sales	21,049	21,406	21,663	22,106	22,339	22,633	22,970	23,181	23,405	23,703
Domestic energy Losses	2,922	3,015	2,874	2,971	3,008	3,067	3,185	2,931	2,981	3,017
Total Export Sales	10,870	9,156	7,839	7,571	7,281	6,976	6,659	6,579	6,343	6,966
Export Transmission Losses	991	844	723	692	662	631	595	586	561	568

(in Millions of Dollars)	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
MH Hydraulic Generation	$ 114	$ 107	$ 102	$ 103	$ 103	$ 103	$ 103	$ 102	$ 102	$ 102
MH Thermal Generation	6	5	33	36	39	40	43	50	53	30
Import Energy (including Wind)	49	117	118	127	135	141	151	156	164	239
Other Costs	2	2	3	3	3	3	3	3	3	3
Total Manitoba Domestic Energy Sales	1,194	1,264	1,322	1,389	1,451	1,518	1,591	1,661	1,736	1,818
Total Export Sales	354	379	460	469	486	566	575	599	607	755

Average Price ($/MWh)	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
MH Hydraulic Generation	$ 3.34	$ 3.41	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation	73.15	56.97	80.74	88.71	98.82	106.16	111.17	117.14	122.15	145.98
Import Energy (including Wind)	29.33	39.47	57.30	59.55	62.90	64.99	67.10	69.03	71.04	70.20
Total Manitoba Domestic Energy Sales @ meter	56.74	59.06	61.02	62.85	64.93	67.07	69.27	71.65	74.16	76.69
Total Export Sales	32.58	41.38	58.65	61.99	66.77	81.14	86.38	91.09	95.64	108.41

Note: Manitoba Domestic Energy Sales removes the effects of domestic energy losses which is an enhancement to this schedule since PUB/MH II-45(a) was prepared.

PRE-ASK #2

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PUB/MH I-179

Subject: **Tab 13: PUB Directives**
Reference: **Cost Savings Attributable to Head Office**

a) Please provide a breakdown of the lease reductions by facility.

ANSWER:

Please see the following tables for the lease reductions by facility.

in thousands of $

Location	Annual Rent	Annual Common Area Maintenance	Operations	Business & Property Taxes	Total lease facility savings
1080 WAVERLEY	$ 27	$ 3	$ 25	$ 11	**$ 65**
1090 WAVERLEY	292	33	128	138	**591**
1100 WAVERLEY Bay 2 to 11	260	-	-	91	**351**
1100 WAVERLEY Bay 12 to 15	82	-	-	30	**112**
1100 WAVERLEY bay 16 to 17	56	-	-	20	**76**
1120 WAVERLEY	141	6	35	57	**240**
1140 WAVERLEY	250	22	103	93	**468**
1146 WAVERLEY Bay 1 to 4	97	29	81	27	**234**
1146 WAVERLEY Bay 5 to 8	102	-	-	27	**129**
1146 WAVERLEY Bay 9 & 10	48	-	-	13	**61**
1146 WAVERLEY Bat 11 to 13	63	-	-	18	**81**
1146 WAVERLEY Bay 14	37	-	-	10	**47**
1150 WAVERLEY B & C	214	41	83	19	**357**
1461 CHEVRIER	110	43	2	10	**166**
1565 WILLSON PLACE/ 900 Waverley	591	-	187	152	**931**
1664 SEEL AVE	23	-	-	-	**23**
185 KING STREET	118	78	84	44	**324**
444 ST. MARY	1,064	724	36	235	**2,060**
693 TAYLOR	118	34	114	54	**319**
756 PEMBINA HIGHWAY	10	-	-	-	**10**
Total	**$ 3,704**	**$ 1,013**	**$ 878**	**$ 1,049**	**$ 6,645**

PUB/MH I-179

Subject: **Tab 13: PUB Directives**
Reference: **Cost Savings Attributable to Head Office**

b) Please provide a breakdown of the estimated $1 million in savings for avoided rent for additional space requirements.

ANSWER:

The $1 million in savings represented in Appendix 13.5 used 444 St Mary Ave costs as a basis and was estimated as follows:

444 St. Mary Projected Costs		
Rent @ $12 / sq ft		$850,000
Common Area Maintenance @ $12 / sq ft		850,000
Parking		300,000
Electric Utility		50,000
Other Operating & Maintenance		50,000
Projected 2009/10 annual facility cost for 444 St. Mary	**$**	**2,100,000**
Number of Employees that Occupied 444 St. Mary		330
Total cost per Employee at 444 St. Mary	$	6,364
Number of additional Employees for 360 Portage		150
Number of additional Employees for 360 Portage X Total cost per Employee at the 444 St. Mary Rate	$	954,545

PUB/MH I-179

Subject: **Tab 13: PUB Directives**
Reference: **Cost Savings Attributable to Head Office**

e) Please provide a quantification of the estimated 10% to 15% productivity savings

ANSWER:

Manitoba Hydro cannot provide a specific quantification of the productivity savings attributed specifically to the new head office as these productivity savings will take time to materialize and the head office component will be intermixed with other factors also contributing to productivity gains. Manitoba Hydro has committed to maximizing the opportunities and savings associated with the new head office but maintains that it is most appropriate to review the costs and savings of the utility from an overall perspective to ensure that costs are fair and reasonable.

Manitoba Hydro understands that companies have experienced savings in the order of 10% - 15% when centralizing their facilities. For illustrative purposes, Manitoba Hydro applied a 10% productivity factor to the salary, benefit and support costs of approximately 2,000 employees that will be located at the new head office, equating to $20 million.

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PUB/MH I-179

Subject: **Tab 13: PUB Directives**
Reference: **Cost Savings Attributable to Head Office**

h) **Please indicate the current occupancy levels of the new head office and 820 Taylor and the relative capacity of each facility.**

ANSWER:

Please see the following table as of March 1, 2010.

360 Portage	occupancy	1,698
360 Portage	fitted capacity	2,274
820 Taylor	occupancy	571
820 Taylor following renovation*	fitted capacity	852

In addition to current occupancy, the buildings are required to meet seasonal, temporary and future growth needs, and must be designed to have proper adjacencies for working groups.

* 80% of the renovation has been completed to date. The entire renovation is expected to be completed by the summer of 2010.

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PUB/MH I-178

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.5 Head Office**

a) Please provide a schedule detailing the all in cost of operating the new head office building including depreciation and interest costs.

ANSWER:

Please see the following table for the information requested for the 2010/11 forecast year.

	Cost(in thousands of $)		Cost/sqft	
Service Type				
Security	$	435	$	0.62
Janitorial		1,340		1.92
Manitoba Hydro internal labour		404		0.58
Maintenance & Repair		501		0.72
Operations		291		0.42
Utilities		230		0.33
Total Operating & Maintenance	$	3,201	$	4.59
Depreciation		3,093		4.43
Interest		15,990		22.92
Property & Business Tax (estimated)		4,863		6.97
Total 360 Portage Operating costs	$	27,147	$	38.91
360 Portage gross area		697,609		

PUB/MH I-178

Subject: **Tab 13: PUB Directives**
Reference: **Tab 13.5 Head Office**

f) **Please provide a breakdown of the Operating and Maintenance costs at 820 Taylor in both dollar terms and on a per square foot basis.**

ANSWER:

Please see the following table for the OM&A costs for 820 Taylor.

Service Type	Cost (in thousand of $)	Cost/sqft
Security	$ 172	$ 0.84
Janitorial	244	1.19
Manitoba Hydro internal labour	545	2.66
Maintenance & Repair	183	0.89
Operations	301	1.47
Utilities	61	0.30
Total Operating & Maintenance	**$ 1,507**	**$ 7.35**
Taylor Gross Area Square Footage	205,000	

CENTRA GAS MANITOBA INC.

2009/10 & 2010/11 GENERAL RATE APPLICATION

UNDERTAKING PROVIDED BY: V. WARDEN

UNDERTAKING NO. 14 - TRANSCRIPT PAGE NO. 838:

Please provide a breakdown of the projected 2010 cost per square foot for 444 St. Mary Avenue and 360 Portage Avenue.

Below is a table containing the projected 2010 cost per square foot breakdown for 444 St. Mary Avenue and the annual projected cost for 360 Portage Avenue. Please note that the projected annual costs for 360 Portage Avenue are preliminary.

444 St. Mary Projected Costs	
Rent @ $12 / sq ft	$850,000
Common Area Maintenance @ $12 / sq ft	850,000
Parking	300,000
Electric Utility	50,000
Other Operating & Maintenance	50,000
Projected Annual Cost for 2010	**$2,100,000**
Square footage	72,688
Cost per square foot	**$29**

360 Portage Projected Costs	
Operating & Maintenance	$3,950,000
Property & Business Tax	6,700,000
Principal & Interest	20,000,000
Projected Annual Cost (annualized)	**$30,650,000**
Square footage	697,609
Cost per square foot	**$44**

PUB/MH II-151

Subject: **Tab 13 Board Directives**
Reference: **PUB/MH I-179 (a) & (h)**

b) **It appears that the square footage used in the analysis provided in exhibit #20 differs from that reported for 444 St. Mary on PUB/Centra I -179 (a). Please re-file the table including the leased square footage[on which base lease rent is determined] of each leased property and the cost per square foot based on total lease facility savings.**

ANSWER:

Please see the following tables.

Location	Total lease facility savings (in thousands of $)	Total Square footage	Cost per Square foot
1080 WAVERLEY	$ 65	2,000	$ 33
1090 WAVERLEY	591	21,867	27
1100 WAVERLEY	540	49,697	11
1120 WAVERLEY	240	19,594	12
1140 WAVERLEY	468	32,051	15
1146 WAVERLEY	552	35,697	15
1150 WAVERLEY B & C	357	17,350	21
1461 CHEVRIER	166	10,000	17
1565 WILLSON PLACE/ 900 Waverley	931	48,075	19
1664 SEEL AVE*	23	N/A	N/A
185 KING STREET	324	18,715	17
444 ST. MARY	2,060	78,642	26
693 TAYLOR	319	13,873	23
756 PEMBINA HIGHWAY**	10	N/A	N/A
Total	**$ 6,645**	**347,561**	**$ 19**

*1664 Seel was a parking lot associated with the Apache Mall (1100,1120,1140,1146 & 1150 Waverley)

** 756 Pembina was a parking lot associated with 693 Taylor.

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PUB/MH II-8

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-11- St. Joseph Wind Farm Development**

a) **Please file a summary of the financial terms of the agreement reached with Pattern Energy as discussed in a Manitoba news release dated March 22, 2010.**

ANSWER:

Manitoba Hydro will provide debt financing to a maximum of the lesser of $250 million or 75% of the total capital cost of the project. Pattern Energy will fully fund its $95 million equity commitment prior to any loan advances being made available from Manitoba Hydro. When the project is completed and final capital costs are known, any overpayment of equity will be refunded. Following project completion, the loan is to be repaid mortgage-style through blended interest and principal payments over 20 years. The principal repayments are accelerated by removing $2 million of principal from each of the last six years and spreading this $12 million equally over the first 14 years. A $10 million revolving reserve loan facility is also available to cover cashflow shortfalls. Principal and interest payments due to Manitoba Hydro will be deducted from amounts owed by Manitoba Hydro to the wind farm for the purchase of energy. Full security provisions applicable to a senior lender will apply.

PUB/MH II-8

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-11- St. Joseph Wind Farm Development**

b) **Please describe the financial due diligence undertaken on Pattern Energy, the Companies credit rating and file any external or internally created credit rating reports on the company.**

ANSWER:

Manitoba Hydro undertook extensive due diligence with the assistance of qualified external legal, engineering and financial market experts. Pattern Energy is privately held so no credit ratings are available. Project financing relies on the strength of the underlying project to secure the debt. Manitoba Hydro is protected by its position as off-taker of the power, its security interest in the assets and the requirement for Pattern to fully fund their $95 million equity commitment before having access to the credit facilities.

PUB/MH II-8

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-11- St. Joseph Wind Farm Development**

c) **Please provide a full description of Pattern Energy, including company history , corporate structure, principles etc.**

ANSWER:

Riverstone Holdings LLC purchased the wind development portfolio of Babcock and Brown LP on June 25, 2009 to form Pattern Energy Group LP. Pattern has issued the following description [1] of the company and its principles:

"Pattern is an independent, fully integrated energy company that develops, constructs, owns and operates renewable and transmission energy assets across North America and parts of Latin America. Formerly Babcock & Brown LP's thriving North American energy group, Pattern employs 80 employees, located in four offices (San Francisco, Houston, San Diego and New York), which successfully developed, financed and placed into operation over 2,000 MW of wind power across 11 states. Pattern has a current development pipeline that exceeds 4,000 MW of wind energy and transmission projects in 11 states and 4 countries. Pattern is dedicated to delivering the highest values for our partners and the communities in which we work, while exhibiting a strong commitment to promoting environmental stewardship and corporate responsibility."

[1] *http://www.patternenergy.com/press_releases/2009-0625-PSR-PatternLaunch.pdf*

PUB/MH II-8

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-11- St. Joseph Wind Farm Development**

e) Please explain why Manitoba Hydro is lending Pattern Energy up to $260 million for the development. Is there provisions for loan amounts above $260 million.

ANSWER:

A decision was made to proceed with this unique financing arrangement because the project, which was the lowest cost proposal received during the RFP process, would otherwise not have proceeded in the current difficult climate for financing. Pricing benefits that the developers obtained for the turbines and Federal Eco-Energy funding would have been lost. EcoEnergy funding, worth more than $40 million in this instance, only applies to wind facilities in operation before March 2011. No additional financing is available from Manitoba Hydro in excess of the $250 million construction/term loan or the $10 million reserve loan facilities.

PUB/MH II-8

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-11- St. Joseph Wind Farm Development**

f) Please file a copy of the financial agreements, purchase power agreement and the construction/term loan with Pattern Energy.

ANSWER:

These agreements are commercially sensitive and cannot be provided.

PUB/MH II-8

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-11- St. Joseph Wind Farm Development**

g) Please provide a summary of the terms related to any funds to be lent to Pattern Energy, including funds disbursement and use, interest rate, repayment terms, debt covenants and security.

ANSWER:

The principal terms are provided in the response to PUB/MH II-8(a). No dividends can be paid out unless the debt service coverage ratio in the immediately preceding 12 month period exceeds 1.20. Manitoba Hydro has a first charge on both the assets and the shares of St. Joseph Windfarm Inc. Any additional third party debt must be approved by Manitoba Hydro and must not result in the debt ratio exceeding 75% or the projected debt service coverage ratio to fall below 1.20. The interest rates are considered to be commercially sensitive information.

PUB/MH II-8

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-11- St. Joseph Wind Farm Development**

i) Please compare the financial structure of the St. Joseph wind farm with that of the St. Leon

ANSWER:

Manitoba Hydro has a power purchase arrangement with the St. Leon wind farm but is not involved in its financial structure. In the case of the St. Joseph wind farm, Manitoba Hydro has a power purchase agreement and will be providing debt financing equal to the lesser of $250 million or 75% of the capital cost of the project. The developer will be equity funding the balance.

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PUB/MH II-8

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-11- St. Joseph Wind Farm Development**

j) Please confirm that the output from the St. Joseph wind farm at 138 MW capacity is expected to be 400 to 500 GWh.

ANSWER:

Manitoba Hydro confirms that the expected capacity factor of the 138 MW St. Joseph wind farm would result in a projected annual energy volume that falls within the 400 to 500 GWh range.

PUB/MH II-8

Subject: **Tab 4 Financial Results & Forecast**
Reference: **PUB/MH I-11- St. Joseph Wind Farm Development**

k) **Please confirm that with an estimated capital cost of $345 M, the project revenue requirement (if entirely owned and built by MH) would be in the range of 7 to 8¢/KWh to cover finance, depreciation, and OM&A costs.**

ANSWER:

Manitoba Hydro has no experience with owning or operating a wind farm and cannot confirm these estimates.

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PUB/MH II-7

Subject: **Tab 3 Corporate Overview**
Reference: **Joint Keeyask Development Agreement**

a) **Please provide a summary of the details of the Joint Keeyask Development Agreement (JKDA) and Keeyask Adverse Effects Agreements with Tataskweyak Cree Nation, War Lake First Nation, Fox Lake Cree Nation, and York Factory First Nation. details on the financial and operational commitments. With respect to the JKDA please provide a summary in similar detail with that provided in response to PUB/MH I-4 (c) from the 2008 GRA. Please indicate where the agreement differs materially from that reached in the Wuskwatim development.**

ANSWER:

The Joint Keeyask Development Agreement (JKDA) is available in its entirety on the Manitoba Hydro website at http://www.hydro.mb.ca/projects/keeyask/pdf/JKDA_090529.pdf The Wuskwatim Project Development Agreement (PDA) is also available in its entirety at: http://www.hydro.mb.ca/projects/wuskwatim/pda/Wuskwatim_PDA_ToC.pdf

Manitoba Hydro entered into the Joint Keeyask Development Agreement on May 29, 2009 with the four Keeyask Cree Nations (KCN) or Tataskweyak Cree Nation, War Lake First Nation, York Factory First Nation and Fox Lake Cree Nation. The JKDA was preceded by the signing of the Wuskwatim Project Development Agreement between Manitoba Hydro and the Nisichawayasihk Cree Nation (NCN) in June 2006. Both the Joint Keeyask Development Agreement (JKDA) and the Wuskwatim Project Development Agreement (PDA) provide for equity partnership arrangements between Manitoba Hydro and First Nation communities. However, these agreements were negotiated based on the specific projects under consideration and with communities that had differing interests and expectations with respect to the final business arrangements. Many of the differences between these two agreements are the results of these varying circumstances.

The tables below have been developed to address the questions raised. Table 1 summarizes the details of the financial and operational commitments made in the JKDA and, for comparison purposes, the PDA.

Table 2 summarizes the Adverse Effects Agreements reached for the Keeyask Generating Station Project and the Wuskwatim Project. Although these agreements were negotiated concurrent with the partnership arrangements, the need for these agreements and their implementation exists regardless of whether the KCN or NCN ultimately choose to become equity partners in the Keeyask or Wuskwatim developments. These agreements provide mitigation measures, community-based programming and cash compensation to avoid, offset or compensate for anticipated project effects. Unlike past developments, they have been negotiated prior to the start of project construction and are based equally on community and corporate views of potential project effects.

TABLE 1: FINANCIAL & OPERATIONAL COMMITMENTS IN THE JKDA & PDA

DESCRIPTION	KEEYASK JKDA	WUSKWATIM PDA
Nature of Agreement	A partnership between Manitoba Hydro and the four Keeyask Cree Nations (KCN) to build and operate the Keeyask Generating Station. The assets of the Partnership would consist of the Keeyask Generating Station and, to the degree required, a small amount of working capital. The capital cost would include planning studies, engineering and licensing from April 1, 2002 plus the unamortized balance of prior expenditures.	A partnership between Manitoba Hydro and Nisichawayasihk Cree Nation (NCN) to build and operate the Wuskwatim Generating Station. The assets of the Partnership would consist of the Wuskwatim Generating Station and, to the degree required, a small amount of working capital. The capital cost would include planning studies, engineering and licensing from April 1, 2002 plus the unamortized balance of prior expenditures.
Income/Investment Arrangements	The KCN can choose a preferred equity or a common equity option. This selection must be made prior to or at Final Closing and the two options can not be combined (although each community will make its own choice of option).	Common equity option only.
Debt Equity Ratio of Partnership	The Partnership will be financed by 75% debt and 25% equity. During the first 10 years the debt ratio may temporarily rise up to 85% if required to finance cash calls.	The Partnership will be financed by 75% debt and 25% equity. During the first 10 years the debt ratio may temporarily rise up to 85% if required to finance cash calls.

DESCRIPTION	KEEYASK JKDA	WUSKWATIM PDA
Common Equity Option	Limited Partnership option with an interest of up to 25%. Manitoba Hydro, through a holding company as General Partner, would have a 0.01% interest, with Manitoba Hydro as a Limited Partner holding the balance.	Limited Partnership option with an interest of up to 33%. Manitoba Hydro, through a holding company as General Partner, would have a 0.01% interest, with Manitoba Hydro as a Limited Partner holding the balance.
• *Minimum Investment Required by Cree Nations*	The KCN are required to invest a minimum of $12.5 million with a $2.25 million down payment at initial closing (roughly the start of generating station construction).	NCN's minimum investment is $5 million with a $1 million down payment at initial closing (timed to coincide with the start of access road construction).
• *Amount Manitoba Hydro will lend the Cree Nations to Finance Their Investment*	Manitoba Hydro will lend the KCN a maximum amount equal to the difference between $25 million and the amount it takes to acquire a 17.5% common equity ownership in the Keeyask partnership, financed by the KCN's own money and Manitoba Hydro equity loans. If the KCN invest the minimum of $12.5 million, Manitoba Hydro will lend the KCN the difference between $12.5 million and the amount it takes to acquire 8.75% common equity ownership in the Keeyask partnership, financed by the KCN's own money and Manitoba Hydro equity loans. If the KCN invest their own money in an amount between $12.5 million and $25 million, the Hydro loan would be scaled accordingly.	Manitoba Hydro will provide NCN with equity loans of up to 4 times their cash investment to achieve up to 27.5% common equity ownership in the Wuskwatim partnership, financed by NCN's own money and Manitoba Hydro equity loans.

DESCRIPTION	KEEYASK JKDA	WUSKWATIM PDA
• *Interest Rates on Loans*	The interest rate for project debt - i.e. the financing of the project's capital requirements - is based on Manitoba Hydro's cost of borrowing without markup. Equity loans, cash call loans and dividend loans from Manitoba Hydro to the KCN have a markup of 2% during construction and for all years of operation.	The interest rate for project debt - i.e. the financing of the project's capital requirements - is based on Manitoba Hydro's cost of borrowing without markup. Equity loans, cash call loans and dividend loans from Manitoba Hydro to NCN have a markup of 3% except for the construction period and first 10 years of operations when the equity loan markup is 1%.
• *Period during which Loans are Available*	Equity loans have a term of 50 years. At the end of that term, KCN may utilize a third party lender subject to Manitoba Hydro's right of first refusal.	Equity loans have a term of 50 years. At the end of that term, NCN may utilize a third party lender subject to Manitoba Hydro's right of first refusal.
• *Distributions From Partnership Profits*	Distributions will be payable each year as long as there is enough equity to meet the 25% requirement plus any reserves to cover future costs. No distinction is made between the units purchased by cash and those purchased by loans. KCN will receive 20%-30% of distributions payable on total units, with the balance going to repay the loans. Dividend loans are available based on KCN's own cash investment.	Distributions will be payable each year as long as there is enough equity to meet the 25% requirement plus any reserves to cover future costs. NCN will receive 100% distributions payable on its cash units but will receive distributions from loaned units only after the loans are paid off.
Preferred Equity Option	The preferred equity option would provide a more certain income stream with less downside risk but also less upside potential.	No preferred equity option is currently in place for Wuskwatim.

DESCRIPTION	**KEEYASK JKDA**	**WUSKWATIM PDA**
• *Minimum Investment Required by Cree Nations*	Same minimum investment as for the Common Equity Option. The KCN are required to invest a minimum of $12.5 million with a $2.25 million down payment at initial closing.	N/A
• *Maximum Cree Nations Investment*	Under the preferred option, each of the KCN can only invest up to a maximum of their applicable share of 2.5% of project equity.	N/A
• *Amount Manitoba Hydro will lend the Cree Nations to Finance Their Investment*	No loans are available to the KCN for the purchase of preferred equity shares.	N/A
• *Distributions From Partnership Profits*	Distributions will be payable each year based on a Preferred Distribution Formula outlined in the JKDA.	N/A
Final Closing	Final Closing is 6 months after the last generating station unit is in service.	Final Closing is when the first generating station unit is in service.
Charging of Costs to Partnership	Operating and administrative costs will be without markup and charged in a similar manner to Manitoba Hydro's other generating stations. Applicable transmission costs and associated interest will be recovered annually by means of a 50 year "mortgage". Financial accounting will comply with the standards applied by Manitoba Hydro to its operations.	Operating and administrative costs will be without markup and charged in a similar manner to Manitoba Hydro's other generating stations. Applicable transmission costs and associated interest will be recovered annually by means of a 50 year "mortgage". Financial accounting will comply with the standards applied by Manitoba Hydro to its operations.

DESCRIPTION	KEEYASK JKDA	WUSKWATIM PDA
Terms of Cash Flows	Life of the Project; minimum of 67 years, probably 100 years with refurbishments.	Life of the Project; minimum of 67 years, probably 100 years with refurbishments.
Basis of Power Purchase Agreement (PPA) and Transmission-Costing Arrangements	PPA formula and net revenue to KCN and contribution to transmission costs were established on the basis of an economic calibration. The project was evaluated to determine the net benefit to the integrated system using system models and economic projections. Revenues received by the Partnership from the sale of power to Manitoba Hydro would be based on the actual output of the Keeyask Generating Station and be priced in accordance with an agreed methodology which reflects Manitoba Hydro's actual selling price for exports.	PPA formula and net revenue to NCN and contribution to transmission costs were established on the basis of an economic calibration. The project was evaluated to determine the net benefit to the integrated system using system models and economic projections. Revenues received by the Partnership from the sale of power to Manitoba Hydro would be based on the actual output of the Wuskwatim Generating Station and be priced in accordance with an agreed methodology which reflects Manitoba Hydro's actual selling price for exports.
Responsibilities of Aboriginal Communities for Third Party Liabilities	None	None

TABLE 2: KEEYASK & WUSKWATIM ADVERSE EFFECTS AGREEMENTS

Description	Keeyask	Wuskwatim
Nature of Agreements	Separate agreements between individual KCN communities and Manitoba Hydro which seek to address any potential adverse effects of the Keeyask Project on each community. The agreements were negotiated in advance of project development, but there are clauses which take into account unforeseeable circumstances.	An agreement between NCN and and Manitoba Hydro which seeks to address any potential adverse effects of the Wuskwatim Project on the community. The agreement was negotiated in advance of project development, but includes clauses which take into account unforeseeable circumstances.
Offsetting Programs	Annual funding is provided for a series of programs to offset anticipated adverse effects in the areas of resource access and use, environmental stewardship and cultural sustainability. Funding for specific programs and the duration of this funding vary for each community.	N/A
Financial Compensation	Residual compensation is also provided for adverse effects not addressed by offsetting programs. The amount of residual compensation varies by community consistent with the anticipated adverse effects for each community. Compensation for individual trappers who suffer financial losses is dealt with directly by Manitoba Hydro and not included in the agreements.	The agreement provides financial compensation, payable into a Trust, to offset unavoidable adverse effects. Funds earned by the trust on an annual basis are used for community-based programming and projects determined based on the on the outcomes of a formal Community Approval Process. The agreement also provides compensation for individual trappers who suffer financial loss.